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The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies

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Summary

A decade ago, 158 refineries operated in the United States and its territories and sporadic refinery outages led many policy makers to advocate new refinery construction. Fears that crude oil production was in decline also led to policies promoting alternative fuels and increased vehicle fuel efficiency. Since the summer 2008 peak in crude oil prices, however, the U.S. demand for refined petroleum products has declined, largely due to the economic recession, and the outlook for the petroleum refining industry in the United States has changed.

In response to weak demand for gasoline and other refined products, refinery operators have begun cutting back capacity, idling, and, in a few cases, permanently closing their refineries. By current count, 115 refineries now produce fuel in addition to 13 refineries that produce lubricating oils and asphalt. Even as the number of refineries has decreased, operable refining capacity has actually increased over the past decade, from 16.5 million barrels/day to over 18 million barrels/day. Cyclical economic factors aside, U.S. refiners now face the potential of long-term decreased demand for their products. Legislative and regulatory efforts that originally intended to address the growing demand for petroleum products may now displace some of that demand. These efforts include such policies as increasing the volume of ethanol in the gasoline supply, improving vehicle fuel efficiency, and encouraging the purchase of vehicles powered by natural gas or electricity.

The United States met roughly 39% of its crude oil demand in 2011 through domestic production, exclusive of the natural gas needed in various refining processes. Canada has become the United States' leading supplier of crude oil through its increasing production from oil sands providing roughly 15% of U.S. demand. In total, the United States meets 62% of its demand from crude oil produced in North America. Over the last few decades, imported crude oils have become heavier and higher in average sulfur content. Until quite recently, the diminishing supply of light sweet crude oil led U.S. refineries to make multi-million dollar investments in processing-upgrades to convert lower-priced heavier sour crude oils to high-value products such as gasoline, diesel, and jet fuel.

Some key environmental and energy policies enacted over the past few decades directly or indirectly affect the operations of U.S. refineries and the market for petroleum products. These include requirements for the use of reformulated gasoline (RFG) in many areas of the country, mandates under the federal Renewable Fuel Standard (RFS), increasingly stringent vehicle efficiency standards, and greenhouse gas limits under the Clean Air Act and state laws.

Declining motor-fuel demand spurred by both market and regulatory forces has influenced some refinery operators to idle, consolidate, or permanently close refineries. However, newly available light sweet crudes from North Dakota, Texas, and Ohio are changing refining economics in some regions of the United States.

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Introduction

The U.S. petroleum refining industry experienced what some have called a "golden age" during the years 2004-2007. During this period, the demand for petroleum products, especially gasoline, increased rapidly both in the United States and world markets. Refiners found favorable price-spreads between heavy and light crude oils as well as between crude oil and refined products. The industry operated plants at nearly maximum capacity and posted record profit levels. Unexpected events such as hurricanes that shut down Gulf Coast refineries, concerns over "peak oil" production, and crude oil price speculation likely contributed to spikes in gasoline prices. During the period, many policy makers expressed the concern that U.S. refining capacity was not increasing rapidly enough to keep up with the expected growth in demand for petroleum products. The concern now may be that excess refining capacity has affected bottom-line refining profitability and the ability to meet consumer demand.

Current economic conditions have led to lower refinery utilization rates and recent closure of a few refineries. In a continuing trend, some vertically integrated oil companies (those engaged in all phases of production, refining and marketing) either have divested their refineries or spun them off as separate business units. The concentration of refining capacity in the U.S. Gulf Coast, an outcome of the region's significant petroleum resources and their history of development, influenced the current network of crude oil and product distribution pipelines. New sources of heavy crude oils from Canada and light crude oils from the mid-continent and mid-West are altering the logistics in supplying established refining centers. In the absence of pipeline capacity, existing rail lines are proving a viable alternative. Rail appears to offer an immediate solution to both crude supply and product delivery bottlenecks, as rail-delivered ethanol appears to demonstrate. No matter what the investment, refineries must adapt to changing crude streams to ensure lowest cost of operation, and the largest product/crude price spread. The greatest cost in refining is not capital investment, but crude costs. But, the growing availability of new unconventional oil resources in the mid-continent resources is changing refining economics and profitability on both the East and West Coasts, and perhaps challenging the Gulf Coast's refining center status.

The U.S. refining industry faces a number of new policies that could force downward pressure on refinery numbers, capacity, or utilization:

- Tighter Corporate Average Fuel Economy (CAFE) and vehicle greenhouse gas standards;
- the federal Renewable Fuel Standard (RFS);
- natural gas as a transportation fuel; and
- EPA Mandatory Greenhouse Gas Reporting.

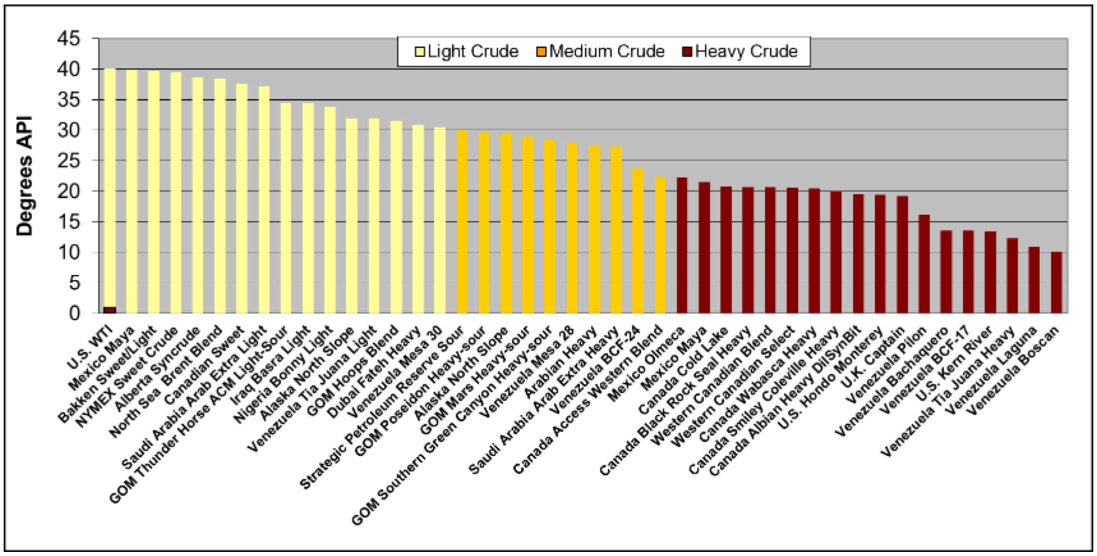
Further, the potential binding greenhouse gas limits in the future, either through a federal cap-and-trade or carbon tax program, or through regulation under the Environmental Protection Agency's "tailoring rule," could provide further downward pressure on petroleum demand.

This report reviews the current production capacity of the refineries operating in the United States, and the sources and changes in their crude oil supply. It also examines the changing characteristics of petroleum and petroleum product markets and identifies the effects of these changes on the refining industry, including tax considerations. It concludes with discussion of the policy and regulatory factors that are likely to affect the structure and performance of the industry during the next decade.

Background: The Basics of Refining Crude Oil

Crude oil is a complex mix of hydrocarbon compounds, ranging from simple compounds with small molecules and low densities to very dense compounds with extremely large molecules. An average crude oil contains about 84% carbon, 14% hydrogen, 1% to 3% sulfur, and less than 1% each nitrogen, oxygen, metals, and salts. The American Petroleum Institute (API) compares the "lightness" or "heaviness" of crude oils on an inverted scale in terms of degrees (º) API gravity.[1] **Figure 1** illustrates a range of crude oil gravities. Any crude above 10 °API will float on water. Light crude's API gravity is higher than 31.1 ºAPI, medium crude between 22.3 °API and 31.1 °API, and heavy crude below 22.3 °API. The benchmark for comparing crudes has been West Texas Intermediate (WTI), or Texas light sweet. Light crude has a low wax-content, and sweet crude has less than 0.5% sulfur. (Refer to **Appendix A** for further information on crude oil properties.)

Figure 1. Suite of Crudes



Source: Canadian Crude Quick Reference Guide Version 0.54, Crude Oil Quality Association, 2009, http://www.coqa- inc.org/102209CanadianCrudeReferenceGuide.pdf; http://www.genesisny.net/Commodity/Oil/OSpecs.html#Top; BP http://www.bp.com/productfamily.do?categoryId=16002776&contentId=7020157; McQuilling Services, LLC, "Carriage of Heavy Grade Oil," Garden City, NY, 2011, http://www.meglobaloil.com/MARPOL.pdf; Hydrocarbon Publishing Co., Opportunity Crudes Report II, Southeastern, PA, 2011, p. 5, http://www.hydrocarbonpublishing.com/ReportP/Prospectus- Opportunity%20Crudes%20II_2011.pdf.

Notes: Light crude > 31.1 °API, medium crude 22.3 - 31.1 °API, and heavy < 22.3 °API.

A hypothetical refinery distills crude oil into various products, according to their boiling point range. The most common products—gasoline, diesel, and jet fuels—are complex mixtures of hydrocarbons that include paraffins, naphthenes, and aromatics (which give fuel its unique odor).[2]

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[1] API gravity scale: light—greater than 30º; medium—22º to 30º; heavy—less than 22º; and extra heavy—below 10º. Formula: (141.5 ÷ relative density of the crude [at 15.5°C or 60°F]) - 131.5.

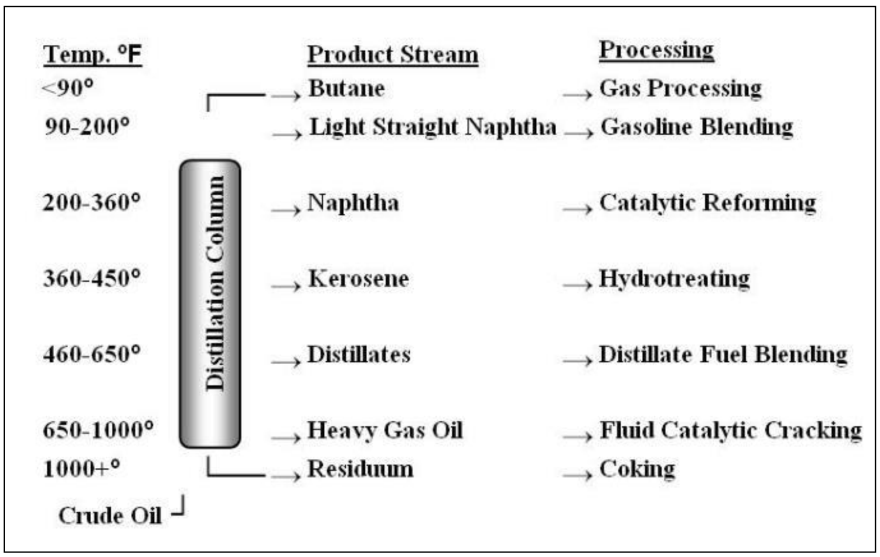
[2] James H. Gary and Glenn E. Handwerk, *Refining Petroleum—Technology and Economics*, 4th Ed., Marcel Dekker, Inc., 2001.

Refineries vary in complexity, but have several basic processing steps in common: *distillation*, *cracking*, *treating* and *reforming*. Distillation involves heating crude oil in a furnace then condensing it in an atmospheric distillation tower (or Crude unit)—the tall, narrow columns that give a refinery its distinctive skyline. The Crude unit separates light hydrocarbon molecules from heavy hydrocarbons based on their boiling temperatures. The lightest materials, like propane and butane, vaporize and rise to the top of the atmospheric column. Medium weight materials, including gasoline, jet and diesel fuels, condense in the middle. Heavy materials, called gas oils, condense in the lower portion of the atmospheric column. Residuum (a heavy tar-like material) referred to as the "bottom of the barrel," has a high boiling temperature that keeps it in the lower portion of the column.

Basic Refining

Refineries have several basic processing steps in common: distillation, cracking, treating and reforming. Topping plants, the simplest refineries, separate crude oil into constituent petroleum products by atmospheric distillation; they produce asphalt and naphtha, but no gasoline. Hydroskimming plants use atmospheric distillation, naphtha reforming and desulfurization process to run light sweet crude to produce gasoline. Cracking plants add vacuum distillation and catalytic cracking process to run light sour crude to produce light and middle distillates. The most complex refineries add coking/resid destruction (delayed coking process) to run medium/sour crude oil.

Figure 2. Generic Distillation Column



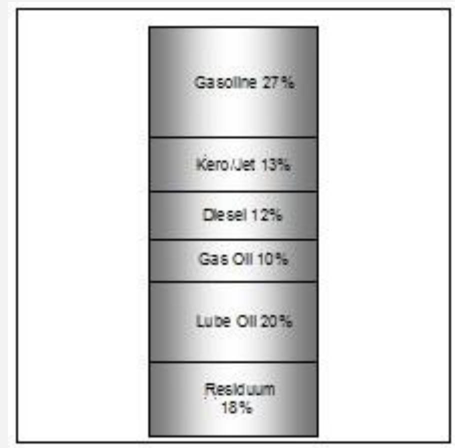
Source: CRS.

Note: For illustrative purposes only.

In some cases, distillation columns operate at less than atmospheric pressure (vacuum) to lower the temperature at which a hydrocarbon mixture boils. Vacuum distillation reduces the chance of thermal decomposition (cracking) due to overheating. As the heavier oils move through the refinery, heat and catalysts "crack" them into lighter products through fluid-catalytic-cracking (FCC), hydrocracking, or thermal-cracking (coking). Fluid catalytic cracking uses high temperature and catalysts to convert heavy gas oil mostly into gasoline. Hydrocracking uses catalysts to react gas oil and hydrogen under high pressure and high temperature to make both jet fuel and gasoline. Coking converts low-value residuum (using thermal-cracking) to high-value light products, producing petroleum coke as a by-product.

While the cracking breaks most of the gas oil into gasoline and jet fuel, it also breaks off some smaller hydrocarbons that are lighter than gasoline. These lighter hydrocarbons recombine in alkylation units, in the presence of sulfuric acid catalyst, to reform into high-octane gasoline. The products from the crude unit and the feeds to other units contain some natural impurities, such as sulfur and nitrogen that contribute to air pollution when fuels combust. Hydrotreating (a milder version of hydrocracking) removes these impurities by converting the sulfur to hydrogen sulfide and then to elemental sulfur; and converting nitrogen into ammonia and then removing it by water-washing for recovery as ammonia for fertilizer.

When refined, a generic 35 °API Crude Oil might yield as much as 27% gasoline and 25% middle distillate fuels



Source: Petroleum Geochemistry and Geology, 1979.

The gasoline stream that comes out of the crude unit or cracking unit has a relatively low octane rating (a key measure of how gasoline performs in an automobile engine). To upgrade gasoline octane-rating, a reforming unit uses precious-metal catalysts (platinum and rhenium) to "reform" hydrocarbon molecules into high-octane gasoline components. The reforming process removes hydrogen from low-octane gasoline, which refinery reuses in various cracking (hydrocracking) and treating (hydrotreating) units.

When refined, a 35 °API crude might yield a product slate range of 27% gasoline and 25% middle distillate fuels in the range diesel and jet fuel. For further information on refining processes refer to **Appendix A**.

Refining Capacity

After a volatile decade marked by record crude oil prices and profit margins, U.S. refiners now face the prospect of possibly long-term decreased demand for their products. Refiners are responding by cutting costs, reducing capacity utilization, and closing facilities.

U.S. Refining Capacity by PADD (2012)

115 refineries, including several refining complexes represent 18 million barrels per day in refining capacity.

PADD	Refineries	Bbl/day
1	7	1,273,000
2	25	3,764,300 1 complex*
3	43	9,256,300 2 complexes*
4	15	632,250
5	25	3,241,800 1 complex*
Total	115	18,167,650

* A complex may include two or more refineries that previously operated independently of each other.

A decade ago, 158 refineries operated in the United States and its territories. By the Congressional Research Service's (CRS) most recent count, 115 refineries primarily process crude oil into fuels (of which four refineries are complexes made up of two or three formerly independent refineries joined by pipeline). Despite permanent closures, operable refining capacity has increased over the past decade from 16.5 million barrels/day to approximately 18 million barrels/day. By the Energy Information Administration's (EIA) definition, "operable capacity" includes both operating refineries and idle refineries which shut down temporarily for repair or "turn around" for seasonal adjustment in the product slate (for example, reformulating gasoline from winter to summer blends). EIA includes refineries that also produce lubricating oils, asphalts, and other products For this report, CRS reviewed petroleum refiners that primarily produce fuel and used the capacity that these refiners advertise on their corporate web pages to estimate an overall refinery capacity in excess of 18 million barrels/day. EIA had reported a U.S. operable crude oil distillation capacity of 17.73 million barrels/day and a gross crude oil input of 15.29 million barrels/day in 2011 yielding a refinery utilization capacity at slightly over 86%. As a refinery's year-to-year performance changes (for the reasons noted above) a better measure of capacity may be "barrels/stream day"—the barrels of crude oil input a refinery reports over the number of days it annually operates also termed "utilization." EIA also reported prime suppliers of refined products sold approximately 14.53 million barrels/day.[3] A prime supplier produces, imports, or transports selected petroleum products (motor gasoline, aviation gasoline, kerosene-jet fuel, propane, total distillate and kerosene, and distillate fuel oil) across state boundaries and local marketing areas, and sells the product to local distributors, local retailers, or end users.

A 95,000-mile network of petroleum product pipelines serves most of the United States, making them interdependent. The West Coast (PADD 5) remains largely isolated from the rest of the United States, especially from the large refineries in PADD 3, as well as crude oil imports to the Gulf Coast. The Virginia and Colonial product pipelines, built during World War II, link up PADD 3 Gulf Coast refineries with PADD 1 northeast states. Regional differences in EPA mandated fuel gasoline specifications, however, limit the flexibility of distribution by pipeline. The isolation has resulted in a gasoline market that has exhibited higher prices and reduced availability under some market conditions. No crude oil pipelines link PADD 1 or PADD 5 with the rest of the country, but rail shipment offers a near-term alternative. Canada supplies PADD 2 refineries through the Alberta Clipper crude oil pipeline. Permitting issues currently stall the Keystone-XL pipeline that would deliver Canadian syncrude (a diluted bitumen from oil sands) to PADD 3 Gulf Coast refineries. **Figure 3** compares each PADD's refining capacity to supplied petroleum products.

Figure 4 provides a general map of refinery locations by "Petroleum Administration for Defense District" (PADD).[4] At one time, refineries in each PADD processed crude oil and distributed petroleum products for use in the district. Maps that are more detailed are available in **Appendix C**. **Table 1** provides refineries by PADD, city, and capacity. CRS count does not include refineries that primarily produce lubricating oils, or asphalt.[5]

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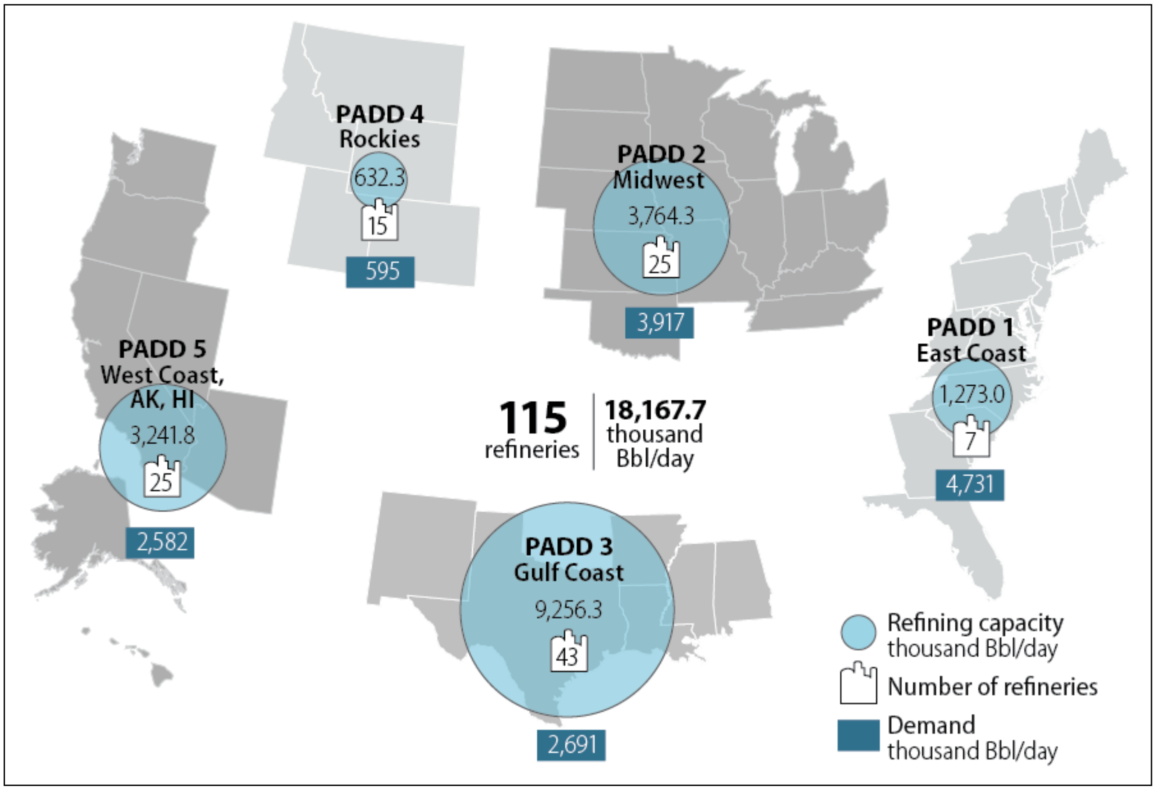
[3] EIA, Prime Supplier Sales Volumes for 2011: http://www.eia.gov/dnav/pet/ pet_cons_prim_dcu_nus_m.htm.

[4] During World War II, the War Department (now the Department of Defense) delineated PADDs to facilitate oil allocation.

[5] To arrive at this number, CRS used U.S. Energy Information Administration and Environmental Protection Agency sources, and then cross-correlated information that refinery operators published on their corporate web pages and in financial statements. CRS also geo-located the refinery sites by using online imagery and mapping tools.

Figure 3. Refining Capacity Vs. Product Supplied (2011)

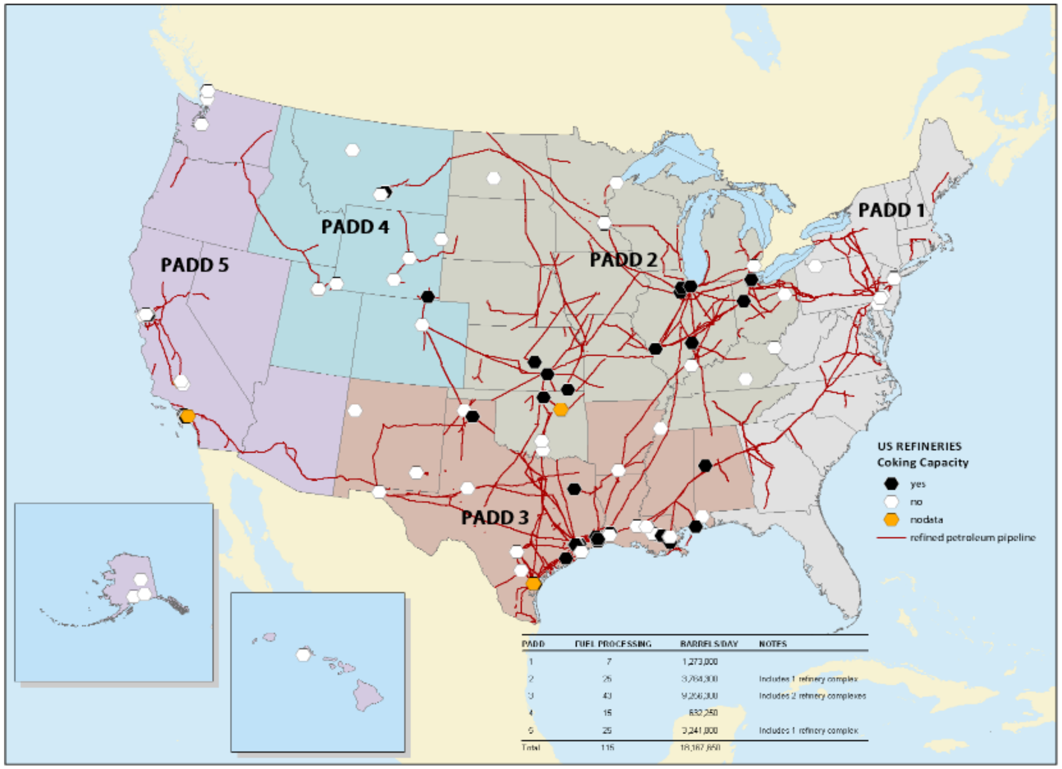
(Thousand Barrels/day [Bbl/Day])



Source: Refining capacity based on CRS analysis of capacity data advertised on owner/operator websites. Demand based on EIA Prime Supplier Sales Volumes for 2011: http://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_m.htm.

Notes: A prime supplier produces, imports, or transports selected petroleum products across state boundaries and local marketing areas, and sells the product to local distributors, local retailers, or end users. Products include motor gasoline, aviation gasoline, kerosene-jet fuel, propane, total distillate and kerosene, and distillate fuel oil.

Figure 4. U.S. Refineries by PADD



Source: Prepared for CRS by the Library of Congress Geography and Map Division.

Table 1. U.S. Refineries by PADD and Advertised Capacity

PADD	ST	Refinery Facility	Advertised Capacity (Bbl/Day)	PADD	ST	Refinery Facility	Advertised Capacity (Bbl/Day)
1	DE	PBF/ Delaware City Refinery	190,000	3	TX	Valero/ Port Arthur Refinery	310,000
1	NJ	Phillips 66/ Bayway Refinery	238,000	3	TX	Lyondell/ Houston Refinery	268,000
1	NJ	PBF/ Paulsboro Refinery	180,000	3	TX	Phillips 66/ Sweeny Refinery Complex	247,000
1	NJ	Amerada Hess/ Port Reading Refinery	70,000	3	TX	Valero/ Texas City Refinery	245,000

PADD	ST	Refinery Facility	Advertised Capacity (Bbl/Day)
1	PA	Carlyle-Sunoco/ Philadelphia Refinery	340,000
1	PA	Delta/Trainer Refinery	185,000
1	PA	United/ Warren Refinery	70,000
2	IL	Phillips 66/ Wood River Refinery	306,000
2	IL	ExxonMobil/ Joilet Refinery	250,000
2	IL	Marathon/ Robinson Refinery	206,000
2	IL	Citgo/ Lemont Refinery	167,000
2	IN	BP/ Whiting Refinery	413,000
2	IN	CountryMark/ Mount Vernon Refinery	26,500
2	KS	Holly-Frontier/ El Dorado Refinery	135,000
2	KS	CVR Coffeyville Refinery	115,000
2	KS	Cenex-NCRA/ McPherson Refinery	85,000
2	KY	Marathon/ Catlettsburg Refinery	233,000
2	KY	Continental/ Somerset Refinery	5,500
2	MI	Marathon/ Detroit Refinery	106,000
2	MN	Flint Hills/ Pine Bend Refinery	320,000
2	MN	Northern Tier/ St. Paul Park Refinery	74,000
2	ND	Tesoro/ Mandan Refinery	58,000
2	OH	PBF/ Toledo Refinery	170,000
2	OH	BP-Husky/ Toledo Refinery	160,000
2	OH	Husky/ Lima Refinery	155,000
2	OH	Marathon/ Canton Refinery	78,000
2	OK	Phillips 66/ Ponca City Refinery	187,000
2	OK	Holly-Frontier/ Tulsa Refining Complex East Holly-Frontier/ Tulsa Refining Complex West	125,000
2	OK	Valero/ Ardmore Refinery	90,000
2	OK	CVR/ Wynnewood Refinery	70,000
2	TN	Valero/ Memphis Refinery	195,000
2	WI	Calumet/ Superior Refinery	34,300
3	AL	Shell/ Mobile Refinery	80,000
3	AL	Hunt/ Tuscaloosa Refinery	72,000
3	AR	Delek-Lion/ El Dorado Refinery	80,000
3	LA	ExxonMobil/ Baton Rouge Refinery	503,500
3	LA	Marathon/ Garyville Refinery	490,000
3	LA	Citgo/ Lake Charles Refinery	425,000
3	LA	Valero/ St. Charles Refinery	270,000
3	LA	Phillips 66/ Alliance Refinery	247,000
3	LA	Phillips 66/ Lake Charles Refinery	239,000
3	LA	Motiva/ Convent Refinery	235,000

PADD	ST	Refinery Facility	Advertised Capacity (Bbl/Day)
3	TX	Total/ Port Arthur Refinery	174,000
3	TX	Valero/ McKee Refinery	170,000
3	TX	Citgo/ Corpus Christi Refinery East Plant Citgo/ Corpus Christi Refinery West Plant	165,000
3	TX	Valero/ Houston Refinery	160,000
3	TX	Flint Hills/ Corpus Christi Refining Complex East	150,000
3	TX	Flint Hills/ Corpus Christi Refining Complex West	150,000
3	TX	Phillips 66/ Borger Refinery	146,000
3	TX	Western/ El Paso Refinery	128,000
3	TX	Petrobras/ Pasadena Refinery	100,000
3	TX	Valero/ Three Rivers Refinery	100,000
3	TX	Marathon/ Texas City Refinery	80,000
3	TX	Alon/ Big Spring Refinery	70,000
3	TX	Delek/ Tyler Refinery	60,000
3	TX	NuStar/ San Antonio Refinery	13,500
4	CO	Suncor Commerce City Refinery complex	98,000
4	MT	ExxonMobil/ Billings Refinery	60,000
4	MT	Phillips 66/ Billings Refinery	58,000
4	MT	Cenex/ Laurel Refinery	55,000
4	MT	MRC/ Great Falls Refinery	10,000
4	UT	Tesoro/ Salt Lake City Refinery	58,000
4	UT	Chevron/ Salt Lake City Refinery	45,000
4	UT	Big West/ North Salt Lake Refinery	35,000
4	UT	Holly-Frontier/ Woods Cross Refinery	31,000
4	UT	Silver Eagle/ Woods Cross Refinery	10,250
4	WY	Sinclair/ Sinclair Refinery	80,000
4	WY	Holley-Frontier/ Cheyenne Refinery	52,000
4	WY	Sinclair/ Little America Refinery	24,500
4	WY	Black Elk/ Wyoming Refinery	12,500
4	WY	Silver Eagle/ Evanston Refinery	3,000
5	AK	Flint Hills/ North Pole Refinery	220,000
5	AK	Tesoro/ Kenai Refinery	72,000
5	AK	Petro Star/ Valdez Refinery	60,000
5	AK	Petro Star/ North Pole Refinery	22,000
5	CA	Chevron/ El Segundo Refinery	290,000
5	CA	Tesoro/ Carson Refinery	266,000
5	CA	Chevron/ Richmond Refinery	243,000
5	CA	Valero/ Benicia Refinery	170,000
5	CA	Tesoro/ Golden Eagle Refinery	166,000

PADD	ST	Refinery Facility	Advertised Capacity (Bbl/Day)	PADD	ST	Refinery Facility	Advertised Capacity (Bbl/Day)
3	LA	Motiva/ Norco Refinery	234,700	5	CA	Shell/ Martinez Refinery	165,000
3	LA	ExxonMobil/ Chalmette Refinery	192,500	5	CA	ExxonMobil/ Torrance Refinery	150,000
3	LA	Valero/ Meraux Refinery	125,000	5	CA	Phillips 66/ Los Angeles Refinery	139,000
3	LA	Alon/ Krotz Springs Refinery	83,100	5	CA	Valero/ Wilmington Refinery	135,000
3	LA	Placid/ Port Allen Refinery	80,000	5	CA	Phillips 66/ San Francisco Refinery/Rodeo	120,000
3	LA	Calcasieu/ Lake Charles Refinery	32,000	5	CA	Tesoro Los/ Angeles Refinery	97,000
3	MS	Chevron/ Pascagoula Refinery	330,000			Alon/ California Refineries Paramount	
3	NM	Holly-Frontier/ Navajo Refinery	100,000	5	CA	Alon/ California Refineries Longbeach	94,000
3	NM	Western/ Four Corners Refinery	23,000			Alon/ California Refineries Bakersfield	
3	TX	Motiva/ Port Arthur Refinery	600,000	5	CA	Kern Oil/ Bakersfield Refinery	26,000
3	TX	ExxonMobil/ Baytown Refinery	573,000	5	CA	San Joaquin Refinery	24,300
3	TX	Marathon/ Texas City Refinery	475,000	5	HI	Tesoro Hawaii Refinery	94,500
3	TX	ExxonMobil/ Beaumont Refinery	365,000	5	HI	Chevron/ Kapolei Refinery	54,000
3	TX	Shell/ Deer Park Refinery	340,000	5	WA	BP/ Cherry Point Refinery	230,000
3	TX	Valero/ Bill Greehy Refinery Complex East Valero/ Bill Greehy Refinery Complex West	325,000	5	WA	Shell/ Puget Sound Refinery	145,000
				5	WA	Tesoro/ Anacortes Refinery	120,000
				5	WA	Phillips 66/ Ferndale Refinery	100,000
				5	WA	US Oil Refinery	39,000

Source: CRS analysis of capacity data advertised on owner/operator websites.

Rail freight and the Class I Railroad System of North America are offering an alternative transport mode that both East Coast and West Coast refiners are turning to for shipping crude from new resources like North Dakota's Bakken Formation. While new pipeline projects can face increasing permitting hurdles and environmental opposition, rail sidings can be quickly constructed and put into service loading rail tank cars. The advantage that freight rail offers in flexibility of delivery, however, may be outweighed by the volumetric advantage that pipelines offer. Although in defense of rail, it has proved viable in shipping ethanol (which now makes up 10% or more of the volumetric consumption of gasoline).[6]

Refinery Closures and Expansions

U.S. refining has experienced some significant capacity losses and additions in the last two years (since CRS first published this report). The Hovic 500,000 barrel/day refinery in St. Croix, Virgin Islands, permanently closed, as did Sunoco's 175,000 barrel/day Marcus Hook Refinery in Philadelphia. The previous owners of the Philadelphia Refinery (340,000 barrel/day) and the Trainer Refinery (185,000 barrel/day) had "idled" their operations, but after a change in ownership are scheduled to reopen. Motiva (Royal Dutch Shell PLC/Saudi Arabia Refining Co.) has doubled the size of its Port Arthur, TX, refinery to 600,000 barrels/day, making it the largest refinery in the United States and one of the largest in the world.[7] Phillips 66 has expanded its Wood River Refinery in Illinois to increase the volume of Canadian heavy crude it can handle.

Crude oil sourcing for U.S. refineries varies over time, but some fundamental changes in supply have recently occurred. PADD 1 (East Coast) refineries that heavily relied on imported crude oil are now looking to unconventional crude from North Dakota and Ohio. PADD 2 (Midwest) and PADD 4 (Rocky Mountains) increasingly depend on crude oil produced and moved by pipeline from Canada and PADD 3 (Gulf Coast) as well as production from the Rocky Mountain states. PADD 3, the largest refining region, obtains crude oil from the Gulf Coast outer continental shelf, Mexico, Venezuela, and the rest of the world. PADD 5 (West Coast) obtains crude oil primarily from Alaska (by tanker) and California, and through imports.

Most of the country's gasoline refining occurs in the Gulf Coast (PADD 3), which makes up nearly 45% of the U.S. refining capacity with 42 refineries processing more than 18 million barrels per day (bbl/d).[8] The Midwest (PADD 2) and the West Coast (PADD 5) follow in capacity. The East Coast (PADD 1) has been losing capacity, giving way to cheaper gasoline imports.

Refinery Capacity Distribution

A different picture of the refining industry base emerges when examining the distribution of refinery capacity. As **Figure 5** shows, a quarter of U.S. refining capacity is concentrated in 11 refineries with capacities exceeding 300,000 barrels/day. These refineries, the largest and most complex in the United States (if not the world) reflect the increased profitability through reduced refining costs that economies of scale bring. All but one refinery have added coking capacity to convert lower value residuum (formerly used as heavy heating oil) to high-value gasoline. European refineries, by comparison, are less complex than U.S. refineries in part because of less coking capacity. The second quartile consists of 16 refineries with capacities between 235,000

[6] Although in the case of ethanol, there may be few options other than rail tanker transport because of potential incompatibility of ethanol with existing pipelines.

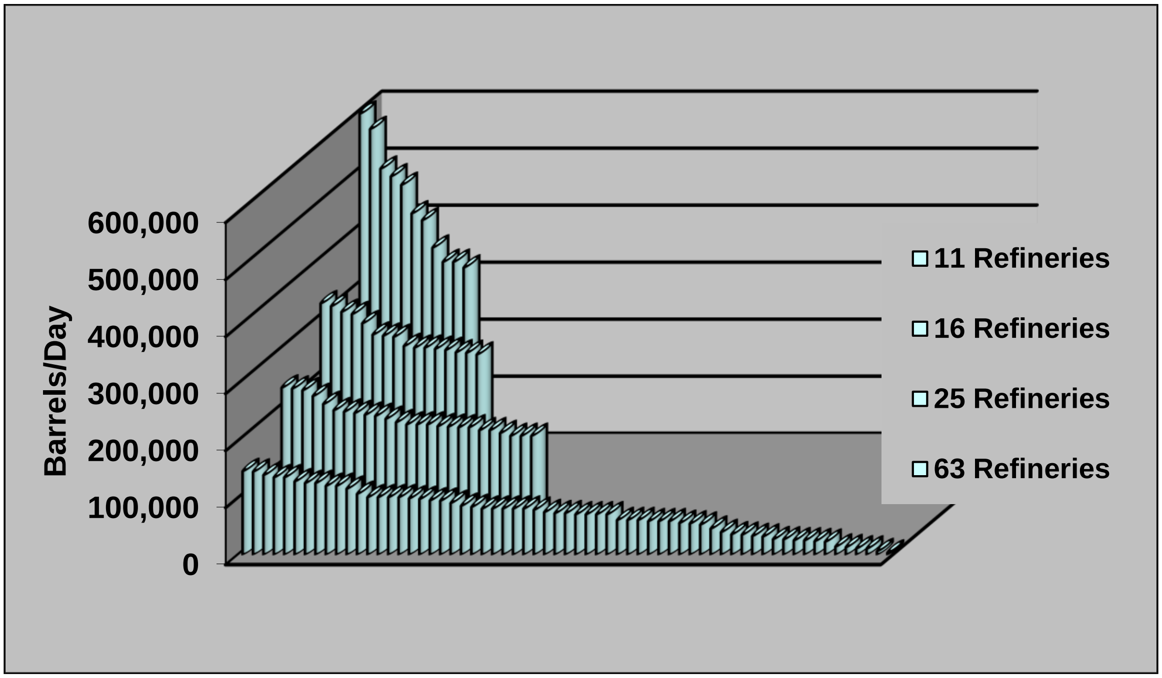
[7] Texas Gulf Coast Online, *Shell Plans Major Expansion of Texas Gulf Coast Refinery*, http://www.texasgulfcoastonline.com/News/tabid/86/ctl/ArticleView/mid/466/articleId/72/Default.aspx.

[8] Texas, 4,747,179 bbl/day and Louisiana, 2,992,123 bbl/day.

and 325,000 barrel/day. (For a further discussion of refinery complexity and processes, refer to **Appendix B**.)

Figure 5. U.S. Refining Capacity Distribution

(Quartile Distribution of Refineries by Capacity)



Source: CRS analysis of capacity data advertised on owner/operator websites.

Notes: Each quartile represents roughly 4.5 million barrels per day in refining capacity. Each bar represents a refinery.

Coking Capacity

> **Coking**
>
> Coking is a severe thermal cracking process that drives off lighter volatile fractions of petroleum that are diverted to a refinery's gasoline processing stream. The carbon end product—"petcoke"—has economic value as a substitute for coal-derived coke used in steel-making. Variations of the coking process include fluid or flexi-coking, delayed coking, and visbreaking.

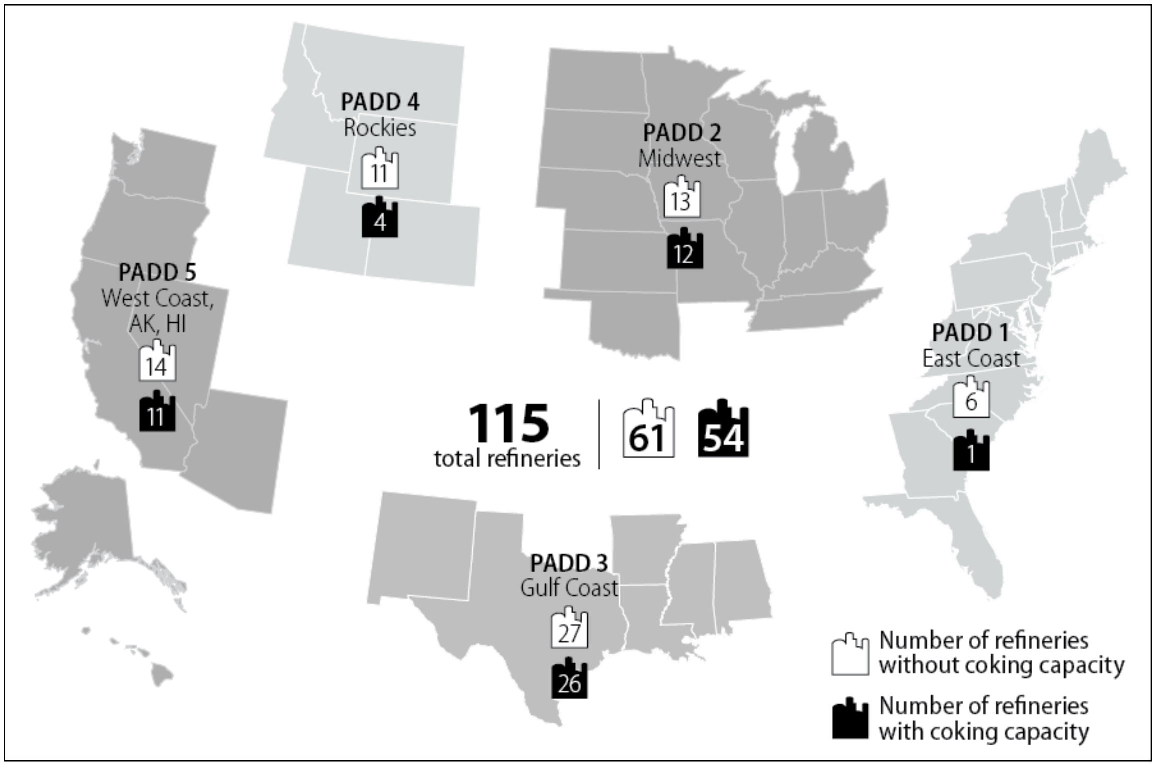
After many electric power plants and industrial plants that had burned heavy, residual fuel oil switched to cleaner burning fuels, refiners were left the residuum or the figurative "bottom of the barrel" to dispose of. A combination of factors including gasoline shortages (the effect of 1970s Arab OPEC oil embargoes), oil price spikes, increased demand for transportation fuels, and the declining availability of light sweet crude oils led refiners to develop "coking" processes to convert high-boiling range residuum to lighter hydrocarbons for making gasoline. Coking has become an increasingly important capability for U.S. refining industry because it has enabled refineries to upgrade a wide range of heavy crude oils to high value fuels. Making better use of the available supply also helped the industry reduce demand for imports and reduce waste stream generation (an environmental benefit); all gains that otherwise would qualify as energy-efficiency improvements.

A coker in various configurations cracks large residuum molecules into smaller molecules by holding the residuum in a coke drum at a high temperature. The solid carbon that remains (petcoke) must be drilled out from the coke drum. Pet-coke increasingly substitutes for coke made from coal for steel-making.

Some 54 refineries have some form of coking capacity, with Gulf Coast refineries (PADD 3) having nearly half—26 (see **Figure 6**). The prevalence of coking capacity in PADD 3 reflects the dependence on imports of heavier crude from the Middle East, Africa, South America, Mexico, and the Gulf of Mexico.

Figure 6. Refineries with Coking Capacity

(2012)



Source: CRS analysis of capacity data advertised on owner/operator websites.

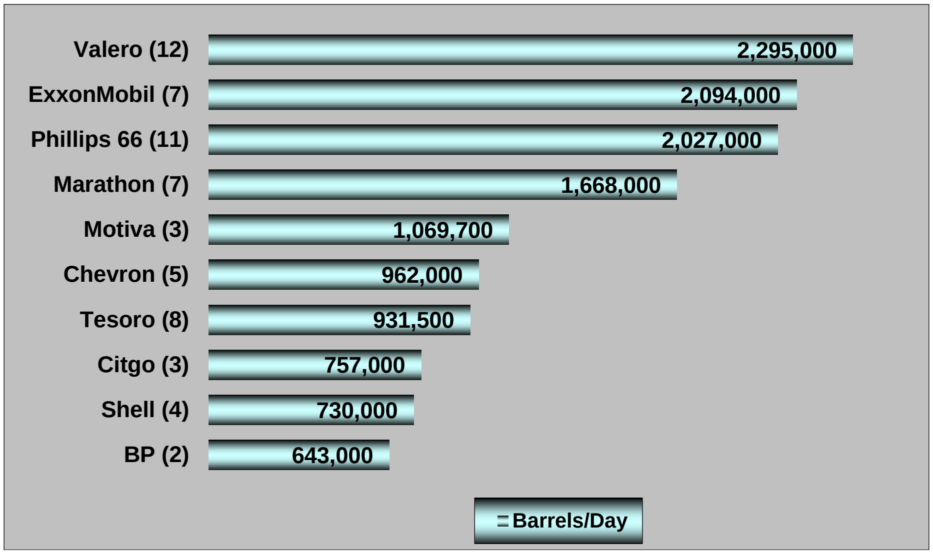
Notes: Number of refineries by PADD with number of refineries having coking capacity.

Major Refiners

Forty-five firms refine petroleum in the United States. The top 10 refiners—Valero, ExxonMobil, Phillips 66 (formerly ConocoPhillips), Marathon, BP, Motiva (a Shell Saudi Arabia Refineries Co. joint venture), Chevron, Tesoro, Citgo, and Shell—account for nearly 75% of total U.S. fuel refining capacity (**Figure 7**). These top ten firms operate more than half of the U.S. fuel refining fleet, a combined 62 out of 115 refineries.

Figure 7. Top Ten U.S. Refiners (2012)

(Advertised Capacity in Barrels per Day)



Source: CRS analysis of capacity data advertised on owner/operator websites.

Notes: Figures in parenthesis indicate number of refineries owned. The top 10 refiners represent roughly 75% of the total fuel refining capacity, some 13.2 million barrels per year. Motiva is a joint venture between Royal Dutch Shell and the Saudi Arabian Refining Co. The Venezuelan oil company Petrovesa owns Citgo.

ExxonMobil, Chevron, Citgo, Shell, and BP engage in all phases of the oil business from producing and refining their own oil to transporting it and marketing at retail. Valero, the largest independent refiner and marketer, does not own petroleum reserves. ConocoPhillips, which had been a fully integrated firm, split its business into upstream (Conoco) and downstream (Phillips 66) business units. Marathon Oil Corporation (an independent upstream company) operates separately from Marathon Petroleum Corporation (a refiner and marketer). The fully integrated firms plus the top two independent refiners and marketers Valero and Tesoro also control the largest refineries.[9]

Crude Oil Supply

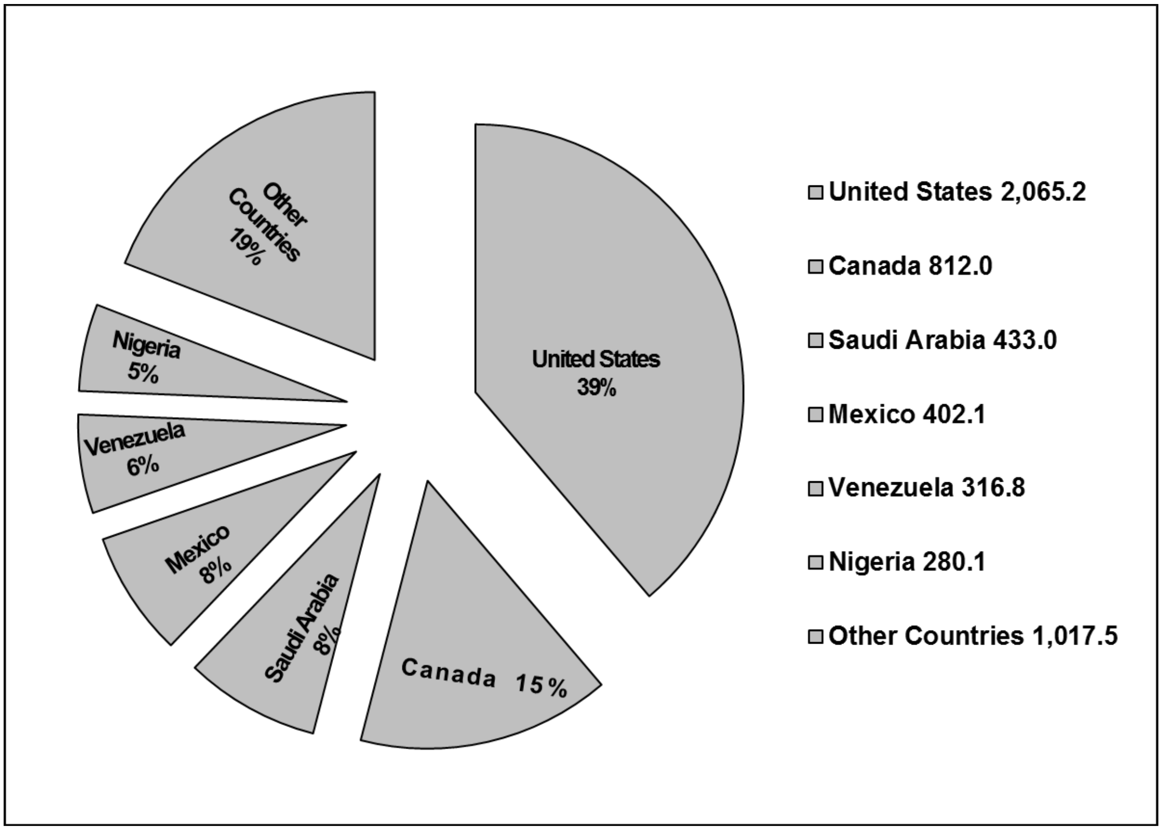
In 2011, the United States consumed 5,327 million barrels of crude oil, importing 3,261 million barrels and producing 2,065 million barrels. The United States met roughly 39% of its crude oil demand in 2011 through domestic production (**Figure 8**). This does not include natural gas needed in various refining processes, nor natural gas and petroleum condensates that are sold directly to retail markets (for example, propane and butane). Canada provided roughly 15% of U.S. demand, followed by Saudi Arabia at 9% (which has directly invested in U.S. refineries to directly refine its exports), and Mexico at 8%. In total, the United States meets 62% of its demand from crude oil produced in North America. Canada has become the United States' leading imported crude oil supplier through its increasing production from oil sands.[10]

[9] Downstream operations include refining and marketing. Not all petroleum products are marketed by the large oil companies. Some retail outlets are company owned, some privately owned.

[10] CRS Report RL34258, *North American Oil Sands: History of Development, Prospects for the Future*, by Marc Humphries.

Figure 8. U.S. Crude Oil Supply

(Million Barrels By Source of Supply for 2011)



Source: EIA U.S. Crude Oil Imports, August 30, 2012, http://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epc0_im0_mbbl_a.htm; and U.S. Crude Oil Production, August 30, 2012, http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm

Notes: In 2011, the United States consumed 5,327 million barrels of crude oil, importing 3,261 million barrels and producing 2,065 million barrels.

While crude oil input to U.S. refineries has decreased somewhat compared to a decade ago, input appears to be on the rise from a low point in 2009 (**Table 2**). In 2011, refineries consumed an average 15.3 million barrels per day of crude oil, an increase of 630 thousand barrels/day over 2009. The increase does not necessarily reflect a rise in U.S. demand, as product exports have been steadily increasing, partly due to ethanol blending into the fuel supply (see "Renewable Fuel Standard /Alternative Fuels.")

Table 2. Gross Input to Refineries

(Thousand Barrels/Day)

Year	Average Daily Input[a]	Daily Input Change	Daily Product Exports[b]
2001	15,352		951
2002	15,180	-172	975
2003	15,508	+328	1,014
2004	15,783	+275	1,021
2005	15,578	-205	1,133
2006	15,602	+24	1,292
2007	15,450	-152	1,405
2008	15,027	-423	1,773
2009	14,659	-368	1,980
2010	15,177	+518	2,311
2011	15,289	+112	2,939

Sources:

a. EIA Petroleum Navigator, Petroleum Supply Annual; Refinery Utilization and Capacity, http://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_a.htm.

b. EIA Petroleum Navigator, U.S. Exports by Destination, http://www.eia.gov/dnav/pet/pet_move_expc_a_EPP0_EEX_mbblpd_a.htm.

Crude oil imports by the United States have declined since the middle of the last decade, while U.S. crude oil production has been increasing. Volumetrically, U.S. crude oil production in 2011 essentially matched the 2003 level of approximately 2.06 billion barrels per day (**Figure 9**).

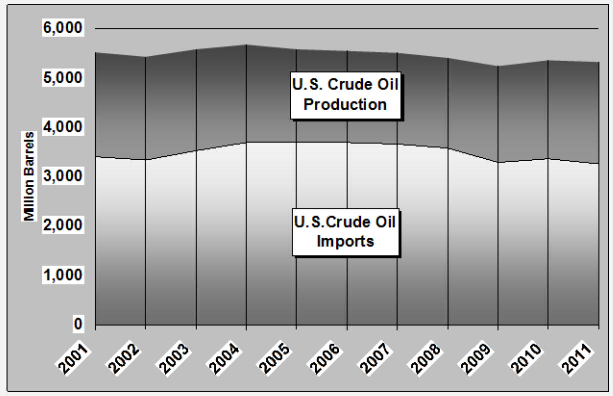
However, the production reflected the new unconventional resources (such as the North Dakota Bakken and Texas Woodford shales) coming online to make up for a decline in production from the Outer Continental Shelf/Gulf of Mexico. While net imports have been declining, Canadian imports have been on a steady rise. The improved trend in U.S. crude production compared to imports in the last several years is more apparent in **Figure 10**. In 2011, imports had declined to roughly 60% of demand.

Changing Crude Oil Grades

Each refinery depends upon a certain grade or blend of crude oils to operate efficiently, depending upon its custom-designed processing equipment. A light crude oil might not be interchanged for heavy crude oil, and without coking capacity a refinery designed to process light sweet crude could not refined heavy sour crude. Some refineries—for example the Citgo refinery (a subsidiary of the Venezuelan National Oil Company)—rely on a very heavy range of crude oil produced in Venezuela, whereas Motiva refineries rely on Saudi Arabian crude oils. Over the last 25 years, the °API gravity of imported crude oils has been decreasing while average sulfur content has been increasing. Until quite recently, the diminishing supply of light sweet crude oil led U.S. refineries to make multi-million dollar investments in processing-upgrades to convert lower-priced heavier sour crude oils to high-value products such as gasoline, diesel, and jet fuel. Newly available light sweet crudes from the North Dakota's Bakken formation are changing refining dynamics in some regions of the United States.

Figure 9. Crude Oil Supply Volume

(U.S. Production vs. Imports)

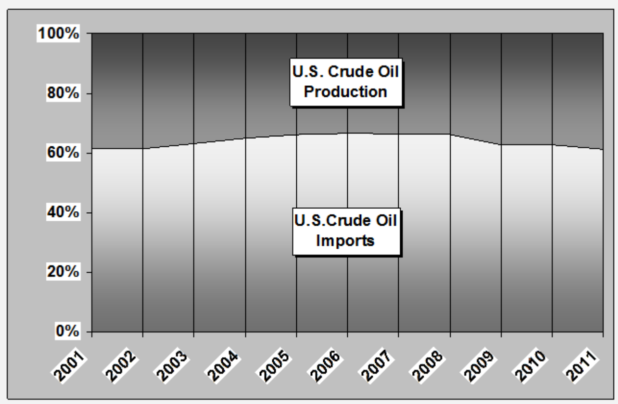


Source: EIA, Crude Oil Production, http://www.eia.gov/dnav/ pet/pet_crd_crpdn_adc_mbbl_a.htm; and U.S. Crude Oil Imports: http://www.eia.gov/dnav/pet/pet_move_impcus_ a2_nus_epc0_im0_mbbl_a.htm.

Notes: Excludes natural gas liquids.

Figure 10. Crude Oil Supply Trend

(U.S. Production vs. Imports)



Source: EIA, Crude Oil Production: http://www.eia.gov/dnav/ pet/pet_crd_crpdn_adc_mbbl_a.htm, and U.S. Crude Oil Imports: http://www.eia.gov/dnav/pet/pet_move_impcus_ a2_nus_epc0_im0_mbbl_a.htm.

Notes: Excludes natural gas liquids.

Bitumen-derived crudes[11] from the Athabasca oil sands of Alberta, Canada, represent an increasingly important feedstock for U.S. refineries. The Enbridge North Dakota pipeline system already pumps Canadian crude oil to PADD 2 refineries, and the proposed Keystone XL pipeline will transport "diluted bitumen (Dilbit)" to PADD 3 refineries.[12] Pumping bitumen-derived crudes by pipeline requires dilution with conventional

[11] Gary R. Brierley, Visnja A. Gembicki and Tim M. Cowan, *Changing Refinery Configuration for Heavy and Synthetic Crude Processing*, UOP LLC Des Plaines, Illinois, USA, 2006.

[12] See CRS Report R41668, *Keystone XL Pipeline Project: Key Issues*, by Paul W. Parfomak et al.

crude oil and gas condensate (a by-product of natural gas production).[13] Dilbit is comparable to other types of heavy crude oils produced in northern California, Nigeria, Russia, Mexico, and Venezuela and currently transported and refined in the United States. If the Keystone-XL Gulf Coast Expansion project is complete, in addition to Canadian crude oil, Keystone will also be able to transport crude oil from U.S. producers in Texas, Oklahoma, Montana, and North Dakota.

Crude Oil Prices

The longstanding benchmark for pricing crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) is West Texas Intermediate (WTI) crude oil; a high-quality crude oil with a 39.6° API gravity (making it a "light" crude oil) and a 0.24% sulfur content (making it a "sweet" crude oil). North Sea Brent crude oil, a 38°-39° API gravity light sweet crude oil but with higher sulfur content than WTI, is a global benchmark for other crude oil grades and is widely used to determine crude oil prices in Europe and in other parts of the world.[14] Although Brent is typically refined in Northwest Europe, it is also exported to the U.S. Gulf and East Coasts.

Historically, the price of WTI has been about $1-$2 per barrel above North Sea Brent crude, and $2-$4 per barrel above the Organization of the Petroleum Exporting Countries (OPEC) "basket" of crude prices.[15] Recently, however, Brent crude has brought a premium of over $10 per barrel against WTI.[16]

OPEC collects price data on a basket of crude oils it produces, and uses the average prices for these oil streams to develop an OPEC reference price for monitoring world oil markets.[17] OPEC's reference basket consists of eleven crude streams representing the main export crudes of all its member countries, weighted according to production and exports to the main markets.[18] According to OPEC, the basket crude has a 32.7 ºAPI gravity, making it heavier than WTI or Brent, and a 1.77% sulfur content, making it sourer. Both of these characteristics tend to make it less valuable than WTI or Brent crude. With the diminishing availability of sweet crudes worldwide, U.S. refiners have increasingly turned to heavier sour crudes, and many refineries have upgraded to refine these crudes.

At the beginning of the U.S. invasion of Iraq in March 2003, the spot price for a barrel of WTI crude oil was $28.11, and prices generally rose during the course of the Iraq War. On a monthly basis, the spot market price of WTI peaked at $133.88 per barrel in June 2008.[19] By February 2009, the price had declined to $39.09 per barrel, only to rise to around $75 per barrel by the end of 2009. In 2012, the average spot price of WTI has been over $96 per barrel.

[13] TransCanada, http://www.transcanada.com/5747.html.

[14] Commodity Online, http://www.commodityonline.com/commodities/energy/brentcrudeoil.php.

[15] On a daily basis the pricing relationships between these can vary greatly.

[16] For a detailed discussion of oil markets, see CRS Report R42024, *Oil Price Fluctuations*, by Mark Jickling and Robert Pirog.

[17] PetroStrategies, http://www.petrostrategies.org/Graphs/OPEC_Basket_Crude_Oil_Prices.htm.

[18] The OPEC basket crude oil streams in the basket are: Saharan Blend (Algeria), Minas (Indonesia), Iran Heavy (Islamic Republic of Iran), Basra Light (Iraq), Kuwait Export (Kuwait), Es Sider (Libya), Bonny Light (Nigeria), Qatar Marine (Qatar), Arab Light (Saudi Arabia), Murban (UAE) and BCF 17 (Venezuela).

[19] On a yearly basis, the average price per barrel of WTI rose every year from 2003 through 2008. The daily peak was attained in July 2008, at over $145 per barrel. See WTI Spot Price data at http://www.eia.gov.

Recently, crude produced from North Dakota's Bakken Formation (a light sweet crude comparable to WTI) has sold in the Midwest at large discounts because of limited pipeline takeaway capacity. Thus, producers have begun shipping Bakken crude to both East and West Coast refineries by rail car. A few PADD 1 refineries that had been idled are able to restart given the newly available lower-cost Bakken.

Beside the political uncertainty introduced by the Iraq War, economists have suggested other reasons for the observed price volatility in crude oil markets, including political tensions in Africa and other regions, financial speculation, currency hedging, inflation hedging, excess demand, supply tightness, and a host of other factors. Widely publicized and debated concerns regarding global "peak oil" production may have contributed to speculation in the oil futures market.[20] Because the U.S. dollar serves as the reference price currency for oil in the world market, some oil analysts link the peak in oil prices in mid-2008 to the dollar's weakness at the time. As a result, the oil price rise was much less pronounced when measured in other major currencies.[21]

Although crude oil represents the primary input and cost factor in refinery operations, the relationship between the price of crude oil and the profit margin in refining is neither simple nor direct.[22] Rising crude oil prices increase primary refining costs and can tighten refining profit margins. However, if product prices rise proportionally to crude oil prices, as they did in 2008, refiners effectively pass cost increases on to consumers. Because of the short-term price insensitivity of demand when gasoline prices rise, the revenue derived from the sale of gasoline and other petroleum products is likely to increase in these market conditions, even as total costs are likely to decrease because the volume of oil passing through the refinery declines somewhat. These factors can permit refiners to maintain or even increase profits during periods of high crude oil prices. The situation differs if less oil is passing through the refinery due to weak product demand. In that event, product prices and profits may fall in tandem as capacity utilization declines.

Table 3. Light/Heavy Crude Oil Price Spread

($/Bbl)

Year	Spread
2006	$15.51
2007	$12.88
2008	$14.85
2009	$5.60
2010	$9.12
2011	-$3.64

Source: EIA.

[20] For background on the subject of peak oil see Kenneth S. Deffeyes, *Beyond Oil: The View from Hubbert's Peak* (Farrar, Straus and Giroux, 2005).

[21] Steve Hawkes, "Oil nears $100 mark as crude reaches yet another record," *Times Online*, October 30, 2007, http://business.timesonline.co.uk/tol/business/industry_sectors/natural_resources/article2767141.ece.

[22] Crude oil generally represents over 50% of the cost of gasoline, the most important refinery product in the United States.

Notes: CRS based calculations on North American crude oils, West Texas Intermediate, and Mexican Maya crude.

The multiplicity of oil prices, which reflect the quality of various crude oils, further complicates the linkage between oil prices and refining profitability. Generally, lighter crude oils command a price premium over heavier oils, as discussed earlier in this report. The size of the price premium tends to vary as relative supply availability changes and as refiners adapt refineries to use lower cost crude oil stocks. The price spread between light and heavy crude oils, shown in **Table 3**, shrank by almost $10 per barrel between 2006 and 2009. After some recovery in 2010, the price premium became negative in May 2011 with Mexican Maya (a heavy crude) commanding a higher price than WTI. During the first eight months of 2012, the price spread remained inverted with Maya priced over $5.71 higher, on average, than WTI.

During the period of high oil prices from 2004 through 2008, heavy crude oils sold at a large discount relative to light crude. The relative tightness in the light crude market, coupled with the price discounts for heavy crude, induced refiners to invest in facilities and processes that would make refineries more able to process heavy crude oils and take advantage of these favorable price spreads. These investments declined in profitability after oil prices fell and the price premium narrowed and inverted in 2011.

Gasoline Demand

The demand for crude oil is derived from the demand for petroleum products. For example, if consumers demand more gasoline, refiners generally purchase and process more crude oil. Afterwards, refiners might adjust their product slate, within technological limits, to yield more gasoline from each barrel of crude oil.

The demand for gasoline depends upon the price of gasoline and the income level of consumers. However, in the short run, the responsiveness of gasoline demand to variations in price is quite low. Estimates of the short-run price elasticity of gasoline are in the range of -0.25 or less.[23] This value implies that if the price of gasoline rises by 1.0% the result is likely to be only a ¼ % decline in the quantity of gasoline demanded. Consumers may have difficulty reducing their demand for gasoline in the short-run, as commuting distance, automobile fuel-efficiency, and other commitments are fixed in the near term, making it hard to lower consumption quickly. They may respond to higher gasoline prices by reducing expenditures on other goods or increasing household debt levels. The demand for gasoline also depends on consumer's income growth, and perhaps, as well, on the fraction of consumer's disposable income accounted for by gasoline purchases. The average estimate of income elasticity for gasoline demand in the United States is about 1.0, meaning that a 1% increase in income is associated with a 1% increase in spending on gasoline. Taken together, these elasticity values imply that gasoline demand may increase, even in

[23] Price elasticity of demand is calculated as the percent change in quantity demanded divided by a specified percentage change in price. The result is a pure number (not measured in any units) that expresses the responsiveness of quantity demanded to changes in the price of the product. A formula to determine price elasticity is e= (percentage change in quantity) / (percentage change in price).

an environment of high or rising prices, as long as the effect of higher incomes outweighs the effect of higher prices.

This condition appears to have been in place in the United States, and much of the world, during the first half of 2008, as well as much of the 2003-2008 period in general. However, after the third quarter of 2008 when U.S. gasoline prices had peaked at over $4.00 per gallon, the economic recession, coupled with expectations of reduced income growth, began moderating the demand for gasoline. After a 0.35% growth in gasoline demand in 2007, demand declined 2.9% in 2008 and continued to fall through 2011, as **Table 4** shows.

Table 4. United States Gasoline Consumption 2006-2009

(Million Barrels/Year)

Year	Consumption	Volume Change	% Change
2006	3,377.2		
2007	3,389.3	12.1	0.35
2008	3,290.1	-99.0	-2.90
2009	3,280.0	-10.1	-0.30
2010	3,283.2	-0.5	-0.01
2011	3,194.7	-88.5	-2.60

Source: Energy Information Administration.

Notes: Gasoline consumption is a measure of product supplied as finished motor gasoline. It includes refinery and blender net production, and imports.

The nearly 6% reduction in gasoline demand, as experienced as the result of the 2007-2008 recession and high prices, may seem minor compared to recessionary demand reductions in other industries. Nonetheless, it was sufficient to create the current weak market conditions (characterized by reduced capacity utilization rates, refinery closures, and weak profitability) that the refining industry has faced over the past two years.

In the longer term, even with more rapid growth in income, the outlook for the gasoline demand in the United States will be constrained by changing attitudes toward petroleum usage, regulations to increase automobile fuel efficiency standards, and regulations mandating the expanded use of alternative fuels in motor transportation.

Refining Profitability[24]

Over the period of 2006 through 2001, leading refiners' net income (profit) generally declined. This may be attributable to several factors including the combination of high crude oil prices and weak demand. The comparative financial performance of the leading firms' downstream business for the 2006 through 2011 period is presented in **Table 5**. High inventories of gasoline and diesel fuel depressed product prices relative to the cost of crude oil, which further reduced refining profit margins.[25] In addition, the narrowing price spread between light and heavy crude reduced the refining margin and contributed to earlier capital investments failing to generate expected returns.

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[24] For a more detailed discussion of oil company profits, see CRS Report R42364, *Financial Performance of the Major Oil Companies, 2007-2011*, by Robert Pirog.

[25] Refining margins are the difference between the value of refined products derived from a barrel of crude oil and the cost of refining that barrel. The gross margin subtracts only the cost of crude oil, while the net margin includes all other operational costs as well as crude oil.

Table 5. Refiners' Net Income, 2006-2011

($ Million)

Company	2006	2007	2008	2009	2010	2011
Valero	5,461	5,234	-1,131	-1,982	324	2,090
ExxonMobil	8,454	9,573	8,151	1,781	3,567	4,459
ConocoPhillips	4,481	5,923	2,322	37	192	3,751
Marathon	2,795	2,077	1,179	464	682	549
BP	5,667	3,569	4,176	4,517	7,239	5,474
Shell	6,989	6,624	446	3,054	3,873	4,274
Chevron	3,973	3,502	3,429	565	2,478	3,591
Tesoro	801	566	278	-140	-29	546

Source: *Oil Daily, Profit Profile Supplements,* various issues, 2007-2011.

Notes: Data in the table are downstream net income, which include income derived from refining and marketing. Venezuelan owned Citgo does not publish financial reports. ConocoPhillips split into Conoco and Phillips 66 after 2011. Shell and the Saudi Arabian Refineries Co, are in the Motiva joint venture.

All the major integrated oil companies have experienced mixed returns in the last few years. Valero, an independent refiner and marketer and owner of the most U.S. refineries, experienced a substantial gain in 2011.

Refining Capital Investment

Refiners undertake capital investment for a variety of reasons, for example, expanding existing or creating new production facilities, implementing new or enhanced technology, regulatory compliance, and adapting refineries to available crude oil streams. Facility expansion and new technology implementation are indicators that the industry expects increasing demand and economic growth.

Table 6. U.S. Refining Industry Capital Budget Expenditures, 2008-2010

Year	$ Billion
2005	7.2
2006	9.0
2007	8.3
2008	13.0
2009	10.1
2010	5.3
2011	9.2

Source: *Oil and Gas Journal*, March 7, 2011, p. 26.

Capital improvement and expansion require that an initial outlay of funds in the current time-period be offset by earnings that might accrue far into the future. If this stream of appropriately discounted future earning is greater than the initial outlay, then a capital investment project qualifies for inclusion in the capital budget.[26] Because the estimated earnings stream embodies management's forecast of the industry's future economic potential, increasing capital budgets imply expectations of healthy profitability, while declining budgets imply a weak profit outlook.

Capital spending in the U.S. refining sector has been mixed, as **Table 7** shows. A 22% decline from 2008 through 2009 was followed by an almost 50% decline from 2009-2010. This trend, coupled with recent refinery closures, suggests that the industry does not see a need to expand, though several refineries have increased capacity in the United States.

[26] This method, which is widely employed by economists and financial analysts, is referred to as *Net Present Value*. An alternative measure is calculation of the internal rate of return to a hurdle rate, usually the company cost of capital.

Refinery Investment and Petroleum Product Imports

While imports of crude oil have been an important part of the U.S. energy supply picture for decades, the importance of petroleum product imports also rose before the recession and expansion of U.S. crude oil production. Oil companies can meet increasing/decreasing demand for petroleum products, such as gasoline, in three basic ways. They can build or close refineries, using either domestic or imported crude oil. This strategy puts refinery investment in competition with the companies' other capital projects, but offers the possibility of relatively large increases in supply.

Second, an oil company can expand or reduce the capacity or capacity utilization-rate of existing refineries. Investment in expanded capacity can run parallel to investments made to keep existing refinery assets in compliance with environmental and other regulations affecting the industry. Expansions or contractions in capacity utilization can usually be brought on line faster than new refineries due to simplified permitting requirements, but have the disadvantage of augmenting or reducing capacity in smaller steps.

Third, instead of investing in new refineries or expanding existing ones, an oil company might choose to meet changes in petroleum product demand by varying net imports of finished, or partially finished, products from other areas of the world. The advantage of this approach is twofold. The net imports can be introduced or reduced, relatively quickly, into the domestic market with no requirement for additional capital spending on refining capacity.[27] The imports can be easily expanded, or contracted, should the need arise. Reliance on foreign sources for petroleum products as well as crude oil may add an additional dimension to concerns of energy dependence, even though prices of these products may tend to be the same in domestic and foreign markets.

Cost is likely to determine an oil company's decision on which alternative to use to meet demand variations. If products available on the world market can meet mandated domestic specifications and are available at competitive prices, importing them gives an oil company flexibility while avoiding the long-term commitment of expanding existing, or constructing new capacity.

A look at U.S. total motor gasoline imports over the 2004-2011 period shows that they averaged about 11% of the roughly 9 million barrels per day finished motor gasoline products supplied to U.S. consumers (see **Table 7**). Total petroleum products imports made up about 17% of domestic consumption. The effects of the recession can be seen in the reduced level of imports in 2008 through 2011. Adjustments in imports to reflect reduced demand are likely to be accomplished with fewer losses in domestic employment and economic dislocations than refinery closures. The recent trend in net imports reflects the export of petroleum products by U.S. refineries. Exports have helped maintain capacity utilization rates and have allowed for efficient use of rising U.S. crude oil production.

Table 7. Gasoline Imports Vs. Total Gasoline Supplied

(Thousand Barrels per Day)

Product	2004	2005	2006	2007	2008	2009	2010	2011
Finished Motor Gasoline Imports	496	603	475	413	302	223	134	105
Motor Gasoline Blending Component Imports	451	510	669	753	789	719	741	718
Total Gasoline Imports Subtotal	947	1,113	1,126	1,166	1,091	942	875	823

27 Other investments (e.g., in import facilities or pipeline capacity) may be necessary.

Product	2004	2005	2006	2007	2008	2009	2010	2011
Total Finished Motor Gasoline Supplied	9,105	9,159	9,253	9,286	8,989	8,997	8,993	8,753
Total Petroleum Product Imports	3,057	3,588	3,589	3,437	3,132	2,678	2,580	2,568
Total Petroleum Product Exports (-)	913	1,101	1,144	1,247	1,608	1,777	2,025	2,503
Net Imports	**2,144**	**2,578**	**2,445**	**2,190**	**1,524**	**901**	**555**	**65**

Source: U.S. Energy Information Administration, U.S. Imports by Country of Origin, http://www.eia.gov/dnav/pet/pet_move_impcus_d_nus_Z00_mbbl_a.htm; and Refiner Motor Gasoline Sales Volumes http://www.eia.gov/dnav/pet/pet_cons_refmg_d_nus_VTR_mgalpd_a.htm, Product Supplied http://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbblpd_a.htm.

Notes: Other products include fuel oils, pentanes, LPG, unfinished oils, oxygenates, fuel ethanol, kerosene, naphtha, waxes, and lubricants.

Refinery Tax Considerations

Provisions adopted in the Energy Policy Act of 2005 (EPAct05; P.L. 109-58) allowed taxpayers to expense 50% of qualified investments in refinery assets.[28] Congress adopted this provision to address concerns that domestic refineries would not have the capacity to meet anticipated growth in domestic fuel demand; a condition that has since reversed. The potential for fuel price spikes also rises when domestic refineries operate at near capacity, as there may be insufficient spare capacity to make up for a refinery outage.

The provisions allowing taxpayers to partially expense investments in refinery assets was initially enacted on a temporary basis.[29] Specifically, taxpayers making qualified investments in domestic refinery property used to refine liquid fuel from crude oil (or other qualified fuels) were eligible for the tax deduction if a binding contract for construction of the qualified property had been entered into by January 1, 2008.[30] Further, under EPAct05, it was required that qualifying property be placed in service prior to January 1, 2012. The Emergency Economic Stabilization Act of 2008 (EESA; P.L. 110-343) extended the under-contract and placed-in-service deadlines, such that the incentive is now available for refineries that entered into a binding construction contract before January 1, 2010, and will be placed in service by January 1, 2014.

Allowing taxpayers to expense part of their investment in refinery property reduces the cost of construction, encouraging additional refinery investment. Allowing 50% of refinery investments to be expensed, rather than depreciated over the normal 10-year life, reduces the cost of construction by approximately 5% for taxpayers in the 35% tax bracket.[31] Since the provision is

[28] Internal Revenue Code (IRC) §179C. Under the Modified Accelerated Cost Recovery System (MACRS), petroleum refining assets are depreciated over a 10-year period using a double declining balance method.

[29] For additional background information on energy tax issues, see CRS Report R40999, *Energy Tax Policy: Issues in the 111th Congress*, by Molly F. Sherlock and Donald J. Marples and CRS Report R41227, *Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures*, by Molly F. Sherlock.

[30] Existing refineries may qualify if the installation of new property increases the refinery's capacity by at least 5% or increases the percentage of total throughput attributable to qualified fuels such that it equals or exceeds 25%. All qualifying property must be in compliance with applicable environmental laws on the placed-in-service date.

[31] The present value of a 10-year, double declining balance depreciation per dollar of investment is $0.74 with an 8% nominal discount rate. For every dollar expensed, the benefit of expensing is to increase the present value of deductions by $0.26, and since half of the investment is expensed, the value is $0.13. Multiplying this value by 35% leads to a 4.6% benefit as a share of investment. The value would be larger with a higher discount rate. For example, at a 10% discount rate, the benefit would be 5.4%. The benefit is smaller for firms facing lower tax rates or those with limited tax liability.

temporary, there is an incentive to speed up the investment in refinery capacity so as to qualify for the tax incentive. Nevertheless, the incentive to speed up investment is limited, because the effective price discount is small. Investing in excess capacity that would not otherwise be desirable would either leave the plant idle or provide too much output and lower prices and profits for a period of time. The latter cost should be at least as big as the cost of remaining idle. With a 5% price discount, the interest cost of carrying excess capacity or losing profits could offset the tax credit's value. The estimated reduction in federal receipts associated with provisions allowing taxpayers to expense 50% of qualified investments in refinery assets is presented in **Table 8**. Over the five-year 2009 through 2013 budget window, estimates suggest this provision will cost $3.4 billion.[32]

Table 8. Tax Expenditures for Provisions Allowing Partial Expensing of Refinery Investments

($ Billion)

Year	Revenue Loss
2008	0.4
2009	0.5
2010	0.7
2011	0.8
2012	0.7
2013	0.6

Source: Joint Committee on Taxation.

Notes: Tax expenditures are estimate federal revenue losses associated with special tax provisions.

Energy and Environmental Policy Considerations

The conventional gasoline refined today has changed considerably since the Clean Air Act Amendments of 1990 prohibited lead additives and established requirements for oxygenated gasoline and reformulated gasoline (RFG). Each of the three formulations of gasoline (conventional, oxygenated and reformulated) is available in at least three grades (87, 89-mid grade, and 91+ super) and the volatility is adjusted for winter/summer and northern/southern driving conditions. (For information on other properties such as Reid Vapor Pressure, octane, and cetane refer to **Appendix D**.)

Reformulated Gasoline (RFG) and State "Boutique Fuels"

The Clean Air Act, as amended in 1990, directed the Environmental Protection Agency (EPA) to designate areas not complying with national ambient air quality standards (NAAQS) as ozone "nonattainment areas."[33] Cities with the worst smog pollution are required to reduce harmful emissions that cause ground-level ozone by using reformulated gasoline (known as RFG), which is blended to burn cleaner by reducing smog-forming and toxic pollutants during the summer ozone season. Reformulated gasoline undergoes additional processing to remove volatile components that contribute most to air pollution, and to make it less prone to evaporation.[34] (See **Figure 11**.) In addition to RFG, states with less severe ozone problems may opt into the RFG

[32] U.S. Congress, Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2009-2013*, committee print, 111th Cong., 2nd sess., January 11, 2010, JCS-1-10.

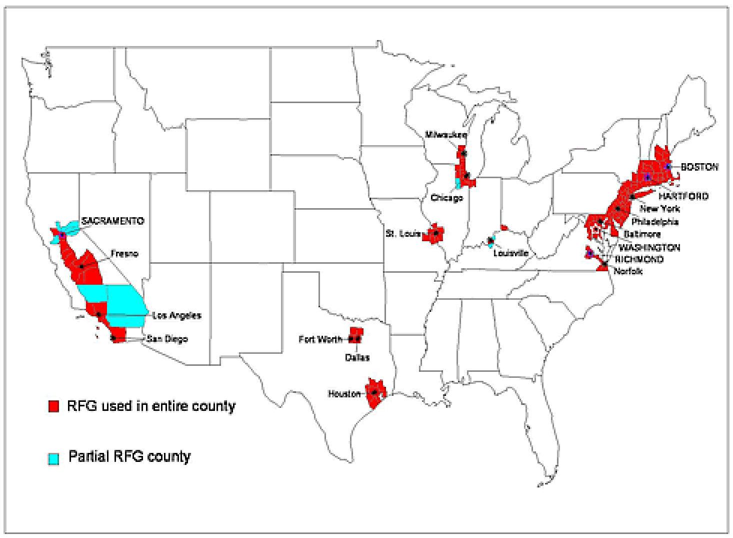
[33] Section 181 of the act required EPA to classify each area as a marginal, moderate, serious, severe or extreme ozone nonattainment area. EPA classified all areas that were designated as in nonattainment for ozone at the time of the enactment of the 1990 Amendments, except for certain "nonclassifiable" areas (56 FR 56694,(1) November 6, 1991).

[34] Reid Vapor Pressure (RVP) is a measure of a fuel's propensity to evaporate. Fuels with higher RVP emit more volatile compounds into the atmosphere, contributing to greater smog formation. See **Appendix D** for a discussion of RVP and other fuel properties.

program or may establish their own fuel standards to address emissions in those areas. These state fuels—often referred to as "boutique fuels"—generally have tighter summer volatility standards than conventional gasoline but not as stringent as federal RFG. Further, the state of California requires its own blend of gasoline across the state.[35] In addition to federal and California RFG, five distinctly formulated summer blends are required in portions of 12 states.[36]

In analyzing the proliferation of gasoline types, EIA concluded in 2002 that: "... the general impact of an increasing number of distinct gasoline fuels with smaller demands and, in some cases, served by fewer suppliers has been to reduce the flexibility of the supply and distribution system to respond to unexpected supply/demand shifts."[37] The prospect that more refineries may sit idle or permanently close due to decreased demand could further reduce that flexibility.

Figure 11. Map of Reformulated Gasoline Areas



Source: EPA.

To reduce the proliferation of boutique fuels, the 2005 Energy Policy Act[38] amended the Clean Air Act (in 42 U.S.C. 7545) by limiting them to the number existing as of September 1, 2004.[39]

Between 1992 and 2005, the Clean Air Act RFG standards included a requirement that the fuel contain oxygen as part of an overall strategy to reduce ground-level ozone and smog. Much of the gasoline sold in the United States during that period was blended with up to 10% methyl tertiary-butyl ether (MTBE) as the oxygenate in almost all RFG outside of the Midwest, while ethanol was used in the Midwest. Both MTBE and ethanol served several functions: as an oxygenate in

[35] In the Los Angeles area, the federal and California standards overlap.

[36] Other state standards (which may or may not be related to emissions controls) also overlap with the RFG and boutique fuels standards in some areas. Depending on how these areas are counted, some in the industry argue that there are 15 distinct blends of gasoline including federal conventional and RFG fuels and various state fuels, although in many cases the fuels produced for these areas are identical.

[37] Energy Information Administration, *Analysis of Selected Transportation Fuel Issues Associated with Proposed Energy Legislation - Summary*, September 2002, http://www.eia.doe.gov/oiaf/servicerpt/fuel/gasoline.html.

[38] Subtitle C—Boutique Fuels Sec. 1541. Reducing the Proliferation of Boutique Fuels.

[39] EPA maintains that list at http://www.epa.gov/oms/fuels/boutiquefuels/boutiquelist.htm.

RFG, as an octane booster, and as a volume extender in conventional gasoline.[40] Groundwater contamination concerns and the State of California's ban on MTBE as a gasoline additive left ethanol as the most popular fuel oxygenate. MTBE was produced and added at the refinery. However, ethanol's corrosive nature makes long-distance shipment of ethanol mixed into gasoline impractical. In consequence, ethanol (produced mostly from corn fermentation in the United States) is blended with gasoline at the storage terminal where the fuel is dispensed to the fuel tank truck. The shift from MTBE to ethanol thus contributed to a reduction in refinery production.

Renewable Fuel Standard /Alternative Fuels

During an era of increasing crude oil prices and concerns for declining domestic crude oil production, many policy makers advocated energy self-sufficiency. Renewable fuels offered the promise of reducing—or at least offsetting an increase in—demand for transportation fuel. Recently motor-fuel demand has declined due both to economic factors and increased use of ethanol and other biofuels. These factors combined may influence operators to idle, consolidate, or permanently close refineries.

Congress created the Renewable Fuel Standard (RFS under Title XV of the Energy Policy Act of 2005 (EPAct; P.L. 109-58) to substitute increasing volumes of renewable fuel for gasoline.[41] EPA has the statutory authority to administer the RFS. The act set a target consumption volume of 7.5 billion gallons of renewable fuels for calendar year 2012. The 2007 Energy Independence and Security Act (EISA; P.L. 110-140) expanded the program to cover transportation fuels in general, extended the program to calendar year 2022, and increased the target volume to 36 billion gallons renewable fuel annually (857 million barrels annually or 2.3 Million bbl/d) (see **Table 9** below).

Table 9. EISA Renewable Fuel Volume Requirement

(Billion Gallons)

Year	Cellulosic Biofuel Requirement	Biomass-based Diesel Requirement	Advanced Biofuel Requirement	Total Renewable Fuel Requirement	Total Renewable Fuel Requirement
2008	n/a	n/a	n/a	9.00	214
2009	n/a	0.50	0.60	11.10	264
2010	0.0065[a]	0.65	0.95	12.95	308
2011	0.0066	0.80	1.35	13.95	332
2012	0.00865	1.00	2.00	15.20	362
2013	1.00	[b]	2.75	16.55	394
2014	1.75	[b]	3.75	18.15	432
2015	3.00	[b]	5.50	20.50	488
2016	4.25	[b]	7.25	22.25	530
2017	5.50	[b]	9.00	24.00	571
2018	7.00	[b]	11.00	26.00	619
2019	8.50	[b]	13.00	28.00	667

[40] Environmental Protection Agency, *Status and Impact of State MTBE Bans*, http://www.eia.doe.gov/oiaf/servicerpt/mtbeban/pdf/mtbe.pdf.

[41] For more information on the Renewable Fuel Standard, see CRS Report R40155, *Renewable Fuel Standard (RFS): Overview and Issues*, by Randy Schnepf and Brent D. Yacobucci.

Year	Cellulosic Biofuel Requirement	Biomass-based Diesel Requirement	Advanced Biofuel Requirement	Total Renewable Fuel Requirement	Total Renewable Fuel Requirement
2020	10.50	b	15.00	30.00	714
2021	13.50	b	18.00	33.00	786
2022	16.00	b	21.00	36.00	857
2023+	c	c	c	c	

Source: EPA Renewable Fuel Standard http://www.epa.gov/otaq/fuels/renewablefuels/.

Notes: 1 barrel = 42 gallons.

a. The initial EISA cellulosic biofuels mandate for 2010 was 100 million gallons. EPA revised this mandate downward to 6.5 million ethanol-equivalent gallons. For 2011 and 2012, the mandates were scheduled at 250 million and 500 million gallons, respectively, but were revised down to 6.6 million and 8.65 million gallons, respectively.

b. To be determined by EPA through a future rulemaking, but not less than 1.0 billion gallons.

c. To be determined by EPA through a future rulemaking.

The 2012 requirement of 15.2 billion gallons of renewable fuels represents roughly 10% of 2012 gasoline and diesel fuel consumption by volume.

As the mandated level of biofuels under the RFS increases, fuel suppliers are rapidly facing a "blend wall" limiting the amount of ethanol they can use in gasoline.[42] Under earlier EPA rules, the maximum ethanol content in gasoline was 10% by volume (E10) for use in conventional vehicles. For flexible fuel vehicles (FFVs), ethanol concentration is capped at 85%. In response to a waiver petition by Growth Energy, EPA granted a partial waiver from the 10% limit, allowing the use of 15% ethanol (E15) in some vehicles. The partial waiver allows the sale of E15 for use in 2001 and newer model year passenger cars and light trucks. EPA denied the waiver to use E15 in vehicles older than model year 2000, and in all heavy-duty, motorcycle, and non-road engines.

However, EPA's approval of the use of E15 only addresses one facet of the blend wall issue. Retail pumps, storage tanks, and other infrastructure may not be compatible with ethanol blends above E15. Further, while EPA allows the use of E15 in newer model year vehicles, no automaker has yet updated their warranties to allow the use of E15. Further, state and local codes and standards may prohibit the storage, use and/or sale of blends above 10%. If fuel suppliers are unable or unwilling to sell E15, they will need to find some other way to address the blend wall.[43] EPA is finalizing RFS regulations for 2011 with specific annual volumes for cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel requirements. Although current ethanol production capacity is more than adequate to meet current blending goals, increased biofuel production faces a number of economic, land use, and policy barriers. The feasibility of expanding current ethanol production by another 1 million bbl/d is linked to the ethanol industry's ability to expand under escalating feedstock prices and economic conditions that discourage capital investment. Congress is also looking toward cellulosic ethanol to meet much of the RFS requirements. However, cellulosic ethanol production has technological barriers to overcome before commercial-scale plants can begin operating.

[42] For a more detailed discussion of these issues, see CRS Report R40445, *Intermediate-Level Blends of Ethanol in Gasoline, and the Ethanol "Blend Wall"*, by Brent D. Yacobucci.

[43] Other ways to address the blend wall include increased use of non-ethanol fuels such as biodiesel, and the increased sale of E85 for use in FFVs.

Carbon Emissions/Greenhouse Gas Rules

Emissions standards for carbon dioxide and other greenhouse gases could dramatically affect the refining industry. Although it is unclear when, or if, federal regulations will affect petroleum refiners, programs in states—especially California—could have a dramatic effect on refining in the future. Similarly, if a federal carbon tax were enacted it would directly affect the price of gasoline and other petroleum products.

On December 15, 2009, EPA finalized rules finding that greenhouse gases endanger public health and welfare, and that emissions from automobiles cause or contribute to that endangerment.[44] The rules follow from a 2007 Supreme Court decision in *Massachusetts v. EPA* that EPA must make a determination under the Clean Air Act one way or the other on the question of greenhouse gas emissions and their effects. The most direct result of that decision was subsequent emissions standards for cars and trucks (see below). However, that determination led to a cascade of other effects, including greenhouse gas emissions controls and permitting requirements on new stationary sources.

However, the automatic thresholds in the Clean Air Act would have caused a massive number of previously unregulated sources to fall under the permitting requirements and would have created an overwhelming burden on federal and state permitting authorities. Thus, in June 2010, EPA finalized the "tailoring rule" limiting at least through 2016 any requirements to only the largest emitters and then generally only if a new project or facility expansion leads to increases of non-greenhouse pollutants as well.

In December 2010 EPA settled a lawsuit petitioning the EPA to set New Source Performance Standards (NSPS) for greenhouse gas emissions from refineries. In the settlement, EPA agreed to promulgate by November 10, 2012, NSPS for greenhouse gas emissions from new and modified refineries, as well as guidelines for existing petroleum refineries. However, this deadline has since passed and it is unclear when EPA will issue a proposal or a final rule.

Future federal regulations, if applied to petroleum refineries, could affect their operations. However, any effects would necessarily come in the future as these regulations do not yet apply to refiners. State regulations, however, could dramatically affect refinery operations, especially rules in the state of California.

In 2007 the California legislature passed, and then-Governor Schwarzenegger signed, a law requiring statewide reductions in greenhouse gas emissions by 2020. Among other regulations to implement the law, the California Air Resources Board established a Low-Carbon Fuel Standard (LCFS) requiring refiners to reduce the carbon intensity[45] of the fuels they provide to the California market. By 2020, the regulations require a roughly 10% reduction from 2010 levels. In general, it is expected that most of the requirement will be met using various lower-carbon biofuels, although California's standards for lifecycle emissions are stringent, and some biofuels actually have higher emissions than gasoline or diesel fuel under the rule.[46] The interactions between the California program and the federal RFS could be complex, and it is unclear how much the LCFS will raise refiners' costs as early reviews of the program have shown little effect

[44] For more information, see CRS Report R41103, *Federal Agency Actions Following the Supreme Court's Climate Change Decision in Massachusetts v. EPA: A Chronology*, by Robert Meltz.

[45] Lifecycle greenhouse gas emissions per unit of energy delivered. Measured in grams of carbon dioxide equivalent of emissions per MegaJoule of energy delivered (gCO_2E/MJ).

[46] See CRS Report R40078, *A Low Carbon Fuel Standard: State and Federal Legislation and Regulations*, by Brent D. Yacobucci.

on the market and compliance credits are currently trading at low levels. However, as the program becomes more stringent, the compliance costs are likely to increase.

Vehicle Fuel Economy/Greenhouse Gas Rules

The most recent federal legislation on fuel efficiency was the Energy Independence and Security Act of 2007 (EISA),[47] which requires the National Highway Traffic Safety Administration (NHTSA) to increase combined passenger car and light truck fuel economy standards to at least 35 miles per gallon (mpg) by 2020,[48] up from roughly 26.6 mpg in 2007.[49] Along with requiring higher passenger vehicle standards, EISA dramatically changed the structure of the passenger vehicle fuel economy program. It also directed DOT to study improvements in heavy-duty vehicles and, if feasible, issue standards for those vehicles as well.[50] In the same year, the Supreme Court found that the Environmental Protection Agency (EPA) has the authority to regulate vehicle greenhouse gas (GHG) emissions under the Clean Air Act.[51] These two actions have significantly changed how motor vehicles are regulated at the federal level.

Fuel consumption and GHG emissions from motor vehicles are closely linked. The vast majority of vehicle GHG emissions result from the burning of petroleum products, so reducing vehicle fuel consumption is the most direct means of reducing emissions. For these reasons, the Obama Administration has issued joint rules on vehicle fuel economy and GHG emissions for model year (MY) 2012-2016 passenger cars and light trucks,[52] MY2014-MY2018 medium- and heavy-duty trucks,[53] and MY2017-MY2025 passenger cars and light trucks.[54] The Administration intends the passenger vehicle standards to be harmonized with standards issued by the state of California under the Clean Air Act.

By 2020, the new passenger vehicle standards will require a combined car/truck fuel economy of an estimated 49.7 mpg, significantly beyond what was required under EISA. Combined, these standards could reduce gasoline consumption by roughly 5 million barrels per day compared to business-as-usual projections, and by roughly 2 million-3 million barrels per day from 2010

[47] P.L. 110-140

[48] Thirty-five miles per gallon is a lower bound: the Administration is required to set standards at the "maximum feasible" fuel economy level for any model year.

[49] Previously, passenger car Corporate Average Fuel Economy (CAFE) standards had been established in 1975 by the Energy Policy and Conservation Act (EPCA, P.L. 94-163), and had not increased beyond that level after 1985. Before the enactment of EISA, DOT had very little authority to modify the passenger car standards. Light truck standards had been flat at 20.7 mpg through the mid-2000s until the Bush Administration used broader authority within EPCA to raise the light trucks standards.

[50] For more analysis, see CRS Report RL34294, *Energy Independence and Security Act of 2007: A Summary of Major Provisions*, by Fred Sissine.

[51] For more analysis, see CRS Report RS22665, *The Supreme Court's Climate Change Decision: Massachusetts v. EPA*, by Robert Meltz.

[52] Environmental Protection Agency (EPA) and National Highway Traffic Safety Administration (NHTSA), "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule," 75 *Federal Register* 25324-25728, May 7, 2010.

[53] EPA and NHTSA, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," 76 *Federal Register* 57106-57513, September 15, 2011.

[54] The CAFE standards only apply through MY2021 because of stipulations in the fuel economy law. NHTSA will need to issue additional regulations for MY2022 onward, while EPA has the authority to set GHG standards for MY2025 and beyond. EPA and NHTSA, *2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards*, Prepublication Version, August 28, 2012, http://www.epa.gov/oms/climate/documents/2017-2025-ghg-cafe-standards-frm.pdf.

levels.[55] Similarly, EPA estimates that the heavy-duty vehicle and engine standards will save 530 million barrels of oil (mostly diesel fuel) over the life of the MY2014-2018 vehicles covered by the rule.[56] Such a dramatic reduction in demand for gasoline will almost certainly affect the overall levels of refined products as well as the mix of products produced from U.S. refineries.

Conclusion

The petroleum refining industry has a long history of cyclical performance. The most recent downturn closely followed a period many identified as the "golden age" of refining. Cycles in the industry have been historically related to movements in the price of oil, which is the primary cost element in refinery operations, and this will likely remain true in the future.

The composition and properties of crude oil inputs to U.S. refineries has shifted over time, requiring investments in new equipment to refine heavier, more sour crudes. As international supply continues to shift toward heavier crudes, investments in these capabilities may increase.

The refining industry also faces structural challenges from recent government policies that aim at directly reducing the demand for the industry's output. Higher fuel mileage standards for automobiles, increased blending of renewable fuels in gasoline and diesel fuel, and the expansion in the use of pure biofuels suggest that even if economic conditions encourage a period of increasing demand for transportation fuels, the need for refined petroleum products will not necessarily increase proportionately. Electric vehicles, if adopted on a large-scale basis, could reduce the demand for liquid transportation fuels of all types, although a large-scale shift in this direction seems unlikely any time soon.

These policies were intended, in part, to address the growing demand for refined petroleum products. Now, though, combined with the prospect of declining motor fuel demand overall, the use of more renewable fuels could influence operators to idle, consolidate, or permanently close refineries. This possibility may help explain why some refiners do not see a need to expand, or even maintain, production capacity in the United States.

Because of market forces, technological changes, and regulatory pressures on the refining industry, additional refineries are likely to close even as some of the more technologically complex and efficient refineries are likely to expand. If a trend toward even larger refineries emerges, this could lead to concentration in the industry at least on the national level. In the event such adjustments occur, Congress may wish to monitor competitive conditions in oil refining, and in particular the impact of consolidation on consumer prices and consumer choice.

[55] CRS analysis of projections from EIA, *Annual Energy Outlook Table Browser*, Washington, DC, Accessed September 21, 2012, http://www.eia.gov/oiaf/aeo/tablebrowser/.

[56] EPA, EPA and NHTSA Adopt First-Ever Program to Reduce Greenhouse Gas Emissions and Improve Fuel Efficiency of Medium- and Heavy-Duty Vehicles, EPA-420-F-11-031, Washington, DC, August 2011, http://www.epa.gov/oms/climate/documents/420f11031.pdf.

Appendix A. Crude Oil Properties

Table A-1. API Gravity and Sulfur Content of Select Crude Oils

Source		Crude Type	°API Gravity	Sulfur %
United States		West Texas Intermediate	40	0.30
		Alaska North Slope	29.5 – 29	1.10
		Alaska North Slope	31.9	0.93
		Strategic Petroleum Reserve sweet/sour	40 – 30	0.5 – 2.0
		NYMEX Deliverable Grade Sweet Crude Oil	42 – 37	<0.42
	Gulf of Mexico	Hoops Blend	31.6	1.16
		Poseidon Heavy-sour	29.7	1.65
		Mars Heavy-sour	28.9	2.05
		Thunder Horse ACM Light-Sour	34.50	0.61
		Southern Green Canyon Heavy-sour	28.40	2.48
	California	Hondo Monterey	19.4	4.70
		Kern River	13.4	1.10
	North Dakota	Bakken Sweet/Light	39.7	0.25
Canada		Access Western Blend	22.3	3.93
		Cold Lake	20.8	3.71
		Black Rock Seal Heavy	20.7	4.59
		Western Canadian Blend	20.7	3.09
		Western Canadian Select	20.6	3.37
		Wabasca Heavy	20.4	4.05
		Smiley Coleville Heavy	20.0	2.97
		Albian Heavy DilSynBit	19.5	2.53
		Canadian Sweet/Sour	37.7 – 37.5	0.42 – 0.56
		Canadian Alberta Syncrude	38.7	0.19
Saudi Arabia		Arabian Heavy	27.5	2.95
		Saudi Arabia Arab Extra Light / Heavy	37.2 – 27.4	1.15 – 2.8
Mexico		Maya	21.5	3.31
		Mexico Maya/Olmeca	39.8 – 22.2	0.80 – 3.30
Venezuela		Pilon	16.2	2.47
		Bachaquero	13.5	2.30
		Tia Juana Heavy	12.3	2.82
		Laguna	10.9	2.66
		Boscan	10.1	5.40
		Mesa 30	30.5	0.85
		Mesa 28	28.0	1.18
		Tia Juana Light	31.9	1.18
		BCF-24	23.7	1.88
		BCF-17	13.5	2.30
Nigeria		Nigeria Bonny Light	33.8	0.30
Iraq		Iraq Basra Light	34 –35	1.5
Dubai		Dubai Fateh Heavy	30.8	2.07
United Kingdom		Captain	19.2	0.70
		North Sea Brent Blend	38 – 39	0.37

Source: Canadian Crude Quick Reference Guide Version 0.54, Crude Oil Quality Association, 2009, http://www.coqa- inc.org/102209CanadianCrudeReferenceGuide.pdf; http://www.genesisny.net/Commodity/Oil/OSpecs.html#Top; BP, http://www.bp.com/productfamily.do?categoryId=16002776&contentId=7020157; McQuilling Services, LLC, "Carriage of Heavy Grade Oil," Garden City, NY, 2011, http://www.meglobaloil.com/MARPOL.pdf; Hydrocarbon Publishing Co., Opportunity Crudes Report II, Southeastern, PA, 2011, p. 5, http://www.hydrocarbonpublishing.com/ReportP/Prospectus-Opportunity%20Crudes%20II_2011.pdf.

Notes: °API gravity is the American Petroleum Institute's measure of specific gravity of crude oil or condensate in degrees. The measuring scale is calculated as Degrees API = (141.5 / sp.gr.60 deg.F/60 deg. F) - 131.5. Higher API degree indicates lighter, and generally higher priced, crude oils.

Light oil, also called conventional oil, has an API gravity of at least 22° and a viscosity less than 100 centipoise (cP).[57] Viscosity is a measure of the fluid's resistance to flow. It varies greatly with temperature. Viscosity matters to producers because the oil's viscosity at reservoir temperature determines how easily oil flows to the well for extraction.

Heavy oil is an asphaltic, dense (low API gravity), and viscous oil that is chemically characterized by its content of asphaltenes (very large molecules incorporating most of the sulfur and perhaps 90% of the metals in the oil). Although variously defined, the upper limit for heavy oil has been set at 22 °API gravity and a viscosity of 100 cP.

Extra-heavy oil is that portion of heavy oil having an API gravity of less than 10°.

Natural bitumen, also called tar sands or oil sands, shares the attributes of heavy oil but is yet more dense and viscous. Natural bitumen is oil having a viscosity greater than 10,000 cP.

Sour crude contains sulfur present as hydrogen sulfide (H2S), which is generated at temperatures greater than 392°F (200°C) by thermolysis of carbon-sulfur bonds in sulfur-containing compounds in the crude. Part of crude oil refining involves removing sulfur by converting it to hydrogen sulfide (H2S). Until the 1970s, refineries burned H2S as a fuel and along with the other gaseous hydrocarbons released during refining. In response to the Clean Air Act, refineries had to add processes that converted the H2S to elemental sulfur.

Natural bitumen is a very viscous crude oil that may be up to 50% by weight of asphaltenes—a general class of aromatic-type hydrocarbons that are very high in molecular weight, highly viscous, and lack a specific melting point. Asphaltenes have a pronounced tendency to "self-aggregate" (self-join), and thus cause problems in crude oil processing and refining. The same property lends itself well to making asphalt (a mixture of asphaltenes and petrolenes) useful for road paving.

SynCrude has no formal definition but typically represents a blend of naphtha, distillate, and gas oil range materials, containing no resid, with a boiling range of 1050°F+ (565°C). Canada began producing oil-sand bitumen in the 1960s by partially refining the bitumen into "synthetic crude" (or "syncrude"). In 1967, Suncor (then Great Canadian Oil Sands) started producing a light sweet syncrude by hydrotreating the naphtha, distillate, and gas oil generated in a refinery delayed coking unit; marketed today as Suncor Oil Sands Blend A (OSA). Syncrude Canada Ltd. started producing a fully hydrotreated syncrude blend in 1978, using fluidized-bed coking technology as the primary upgrading step, marketed today as Syncrude Sweet Blend (SSB). Husky Oil started upgrading a heavy, conventional crude in 1990 using a combination of ebullated-bed hydroprocessing and delayed coking technologies to produce a sweet synthetic crude marketed as Husky Sweet Blend (HSB). Most recently, the Athabasca Oils Sands Project (AOSP) started producing a sweet, synthetic crude in 2003 called Premium Albian Synthetic (PAS) using ebullated-bed hydroprocessing technology.

DilBit, or diluted bitumen, is produced without refinery upgrading, by blending the bitumen with natural gas condensates to meet the specifications required for pipeline shipping. Condensates form when the heavier fractions of natural gas—propane, butane, pentane—turn to liquid in surface processing facilities. Dilbit may be blended with 25%-30% condensate and 70%-75% bitumen. The most common Dilbit streams are Cold Lake Blend (CLB), Bow River (BRH), and various Lloyd blends (LLB, LLK, WCB). Since the majority of condensate is in the C5 to C12 length hydrocarbons (5 to 12 carbon atoms) range, and the majority of bitumen is C30+ boiling

[57] USGS, Heavy Oil and Natural Bitumen—Strategic Petroleum Resources, Fact Sheet 70-03, August 2003, http://pubs.usgs.gov/fs/fs070-03/fs070-03.html

range material, these blends are referred to as "dumbbell crudes," reflecting the absence of intermediate range hydrocarbons.

SynBit is a blend of sweet synthetic crude (typically OSA) and bitumen, typically 50% synthetic crude and 50% bitumen. As natural gas condensate is in short supply in Northern Alberta and sells at a significant premium to light sweet crudes, some producers have started marketing "SynBit." The most common SynBits on the market today are Christina Lake Blend (CSB) and MacKay Heavy (MKH), both of which are blends of bitumen produced by Steam Assisted Gravity Drainage (SAGD) and OSA crudes. As a result of the condensate shortage, some condensate is separated from the SyBits after delivery to the United States, and is being shipped back to Alberta by rail car.

SynDilBits are actually blends of condensate, hydrotreated synthetic crude, and bitumen. They typically contain about 65% bitumen, with the remaining volume split between the two dilutent streams. The most common of these streams are Wabasca Heavy (WH) and Western Canadian Select (WCS).

Appendix B. Refining Processes

Crude oil contains natural components in the boiling range of gasoline, kerosene/jet fuel and diesel fuel. (**Table B-1**.) Light crude oils tend to have more paraffin in the range of gasoline, as much as 10%-40%. When light crude oils were more abundant in the United States, early refineries directly distilled a straight-run gasoline (light naphtha) of low-octane rating.

Table B-1. Crude Oil Fractions and Boiling Ranges

Fraction	Boiling Range °F
Residuum	1,050° +
Gas-oil	520° – 1,050°
Kerosene/Jet/ Diesel	380° – 520°
Gasoline /Naphtha	90° – 380°
Fuel Gases	Below 90°

Source: CRS.

Notes: Gasoline's molecular weight is based on the number of carbon atoms, in the range of C5 to C10; middle-distillate fuels like kerosene, jet, and diesel range from C11 to C18.

Crude oil processing begins in a refinery's atmospheric distillation unit. The refinery's "name plate capacity," usually expressed as barrels per calendar day or barrels per stream day describes the volume of crude oil that flows through a refinery's atmospheric distillation unit. This is the initial refining stage that separates crude oil into gasoline, kerosene, diesel fuel and heavier petroleum components on the basis of their boiling range. There, the "straight-run" petroleum fractions in the boiling ranges of gasoline, naphtha, kerosene, diesel, and jet fuel condense and separate. Heavier fractions are cracked with catalysts and hydrogen to produce more gasoline range (C5+) blending stock, and low-octane paraffins are converted into high-octane aromatics (octane is discussed below). Other processes such as alkylation produce branched chain hydrocarbons in the gasoline range.

Generally, refineries are set up to run specific grades of crude oil, for example light sweet or heavy sour. Light sweet crude is particularly desirable as a feedstock for gasoline refining because its lighter-weight hydrocarbons make it easier to refine. Heavier crude oils require more complex processing than light crudes, and sour crudes require desulfurization. Refineries upgraded to process heavier crudes cannot readily switch back to lighter oils and run at normal capacity.

Catalytic cracking, coking, and other conversion units, referred to as secondary processing units, have enabled refineries to produce more high-value products, such as gasoline, from a barrel of crude oil and process heavier crude oils. These processing units add to a refinery's complexity and can actually increase the volume of its output. These processes also require a supply of hydrogen, typically derived from natural gas.

Table B-2. Refinery Types and Process

Refinery Type	Processes	Complexity
Coking	Add coking/resid destruction (delayed coking process) to run medium/sour crude oil.	9
Cracking	Add vacuum distillation and catalytic cracking process to run light sour crude to produce light and middle distillates.	5
Hydroskimming	Atmospheric distillation, naphtha reforming and desulfurization process to run light sweet crude and produce gasoline.	2
Topping	Separate crude oil into constituent petroleum products by atmospheric distillation; produce naphtha but no gasoline.	1

Source: Reliance Industries, Ltd., "Types of Refinery & Nelson's Complexity."

Notes: Complexity, as denoted above, is based on the Nelson Complexity Index, which rates the proportion of secondary processes to primary distillation (topping) capacity. Nelson's index varies from about 2 for hydroskimming refineries to about 5 for cracking refineries, and over 9 for coking refineries. While the average index for U.S. refineries is 10, only 52 have coking capacity (accounting for the Delaware City refinery closure, this represent 3.485 million barrels per day capacity).[58] By and large, U.S. refineries have become the most complex in the world in order to convert low-value residuum, formerly used as heavy heating oil, to high-value gasoline. European refineries, in comparison, are less complex than U.S. refineries on average, being geared toward producing more diesel fuel.

Distillation Unit: Heats crude oil until it boils and vaporizes. Each hydrocarbon rises to a tray at a temperature just below its own boiling point. There, it cools and turns back to a liquid. The lightest fractions are liquefied petroleum gases (propane and butane) and the petrochemicals used to make plastics and other products. Next come gasoline, kerosene, and diesel fuel. Heavier fractions are used as home heating oil and as fuel in ships and factories. Still heavier fractions are made into lubricants and waxes. The remains, which include asphalt, are known as "residuals."

Fluid Catalytic Cracker: "Cat cracking" is a refining process used to manufacture gasoline. The process uses intense heat, low pressure, and powdered catalyst to accelerate the chemical reaction of the heavy fractions into smaller gasoline molecules.

Selective Hydrocracker: Partially converts diesel-range material into gasoline, propane and butane via a chemical reaction that uses high temperatures and pressures in a catalyst-containing reactor.

Alkylation Plant: Converts light hydrocarbons to heavier hydrocarbons more compatible as gasoline components for high-octane gasoline.

Catalytic Reforming: A process for upgrading low octane naphtha to a high octane gasoline blending component, reformate. Important by-products of this process include hydrogen, benzene, toluene, and xylenes.

Delayed Coker: Converts petroleum pitch into petroleum coke and gas oils for processing in other units to higher quality, higher value diesel fuel and gasoline.

[58] Oil & Gas Journal, 2006 U.S. Refining Survey, December 19, 2005.

Gas Oil Hydrotreater: Provides for removal of sulfur and nitrogen from various products, making them more suitable for conversion feed to other process units.

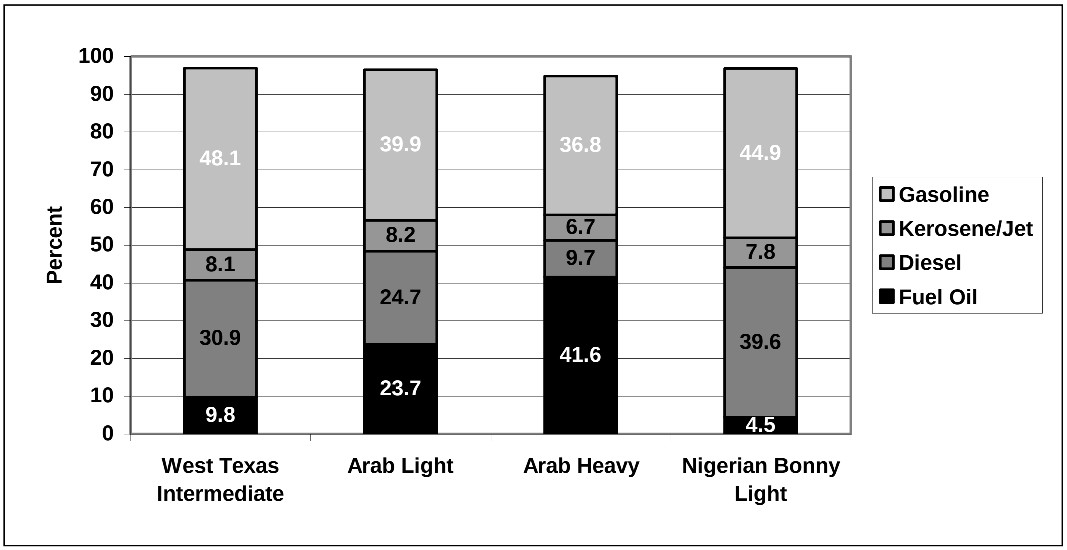
Gas Plants: Collect gases from processing units (hydrocracker, hydrotreater, reformer, coker, cat cracker) and separate volatiles into appropriate product streams.

Sulfur Recovery Unit: Recovers sulfur from refinery streams as elemental sulfur for

A typical refinery yields a limited supply of jet and diesel fuel depending on the type of crude oil processed. Gulf Coast (Texas and Louisiana) may yield up to 8% jet fuel, and over 30% diesel. (See **Figure B-1**.) These refineries have an average complexity of 12 to 13, which is above the national average of 9.5.

Figure B-1. Gulf Coast Refinery Yields

(Percent [%])

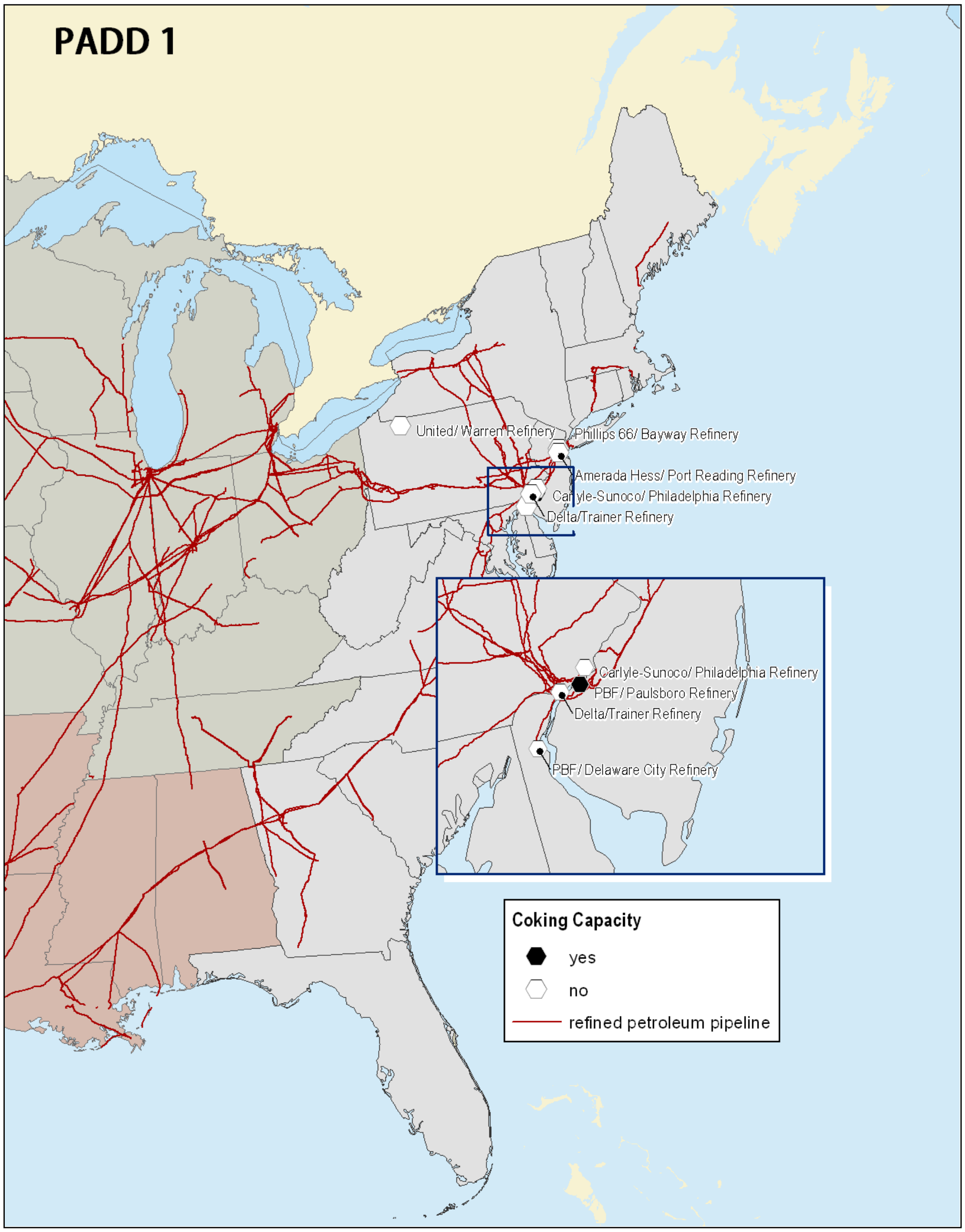


Source: Data used from Energy Intelligence, *The International Crude Oil Refining Handbook*, 2007, http://www.energyintel.com.

Note: Winter yields shown.

Appendix C. Operable Refineries by PADD

Figure C-1. Operable Refineries in PADD 1

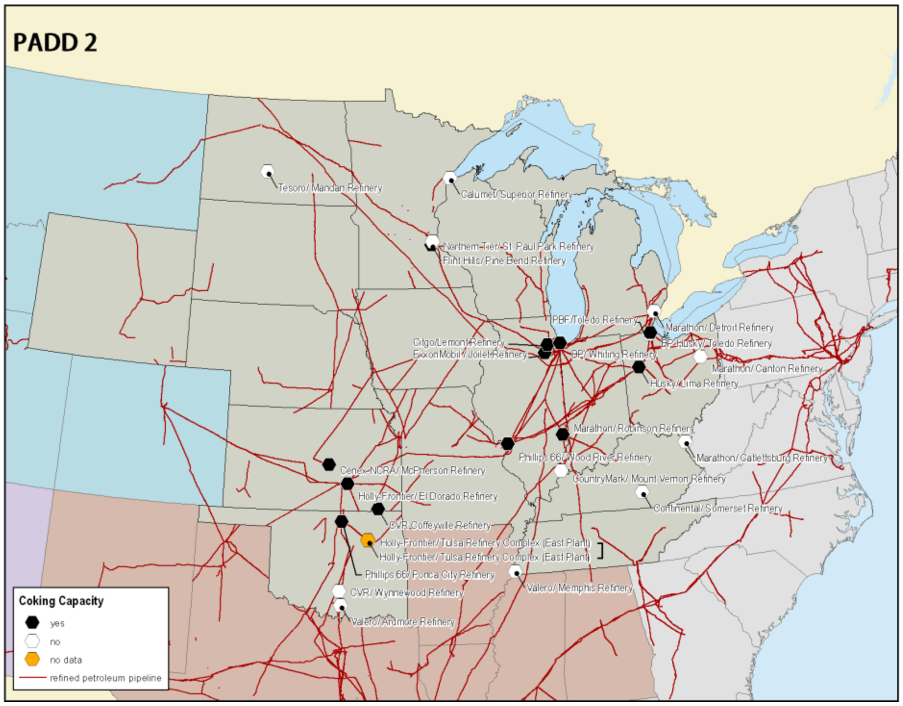


Source: CRS analysis of capacity data advertised on owner/operator websites.

Facility	City	State	Bbl/day
PBF Delaware City Refinery	Delaware City	DE	190,000
Phillips 66 Bayway Refinery	Linden	NJ	238,000
PBF Paulsboro Refinery	Paulsboro	NJ	180,000
Amerada Hess Port Reading Refinery	Port Reading	NJ	70,000
Carlyle -Sunoco Philadelphia Refinery	Philadelphia	PA	340,000
Delta Trainer Refinery	Trainer	PA	185,000
United Warren Refinery	Warren	PA	70,000

Facility	City	State	Bbl/day
			1,273,000

Figure C-2. Operable Refineries in PADD 2

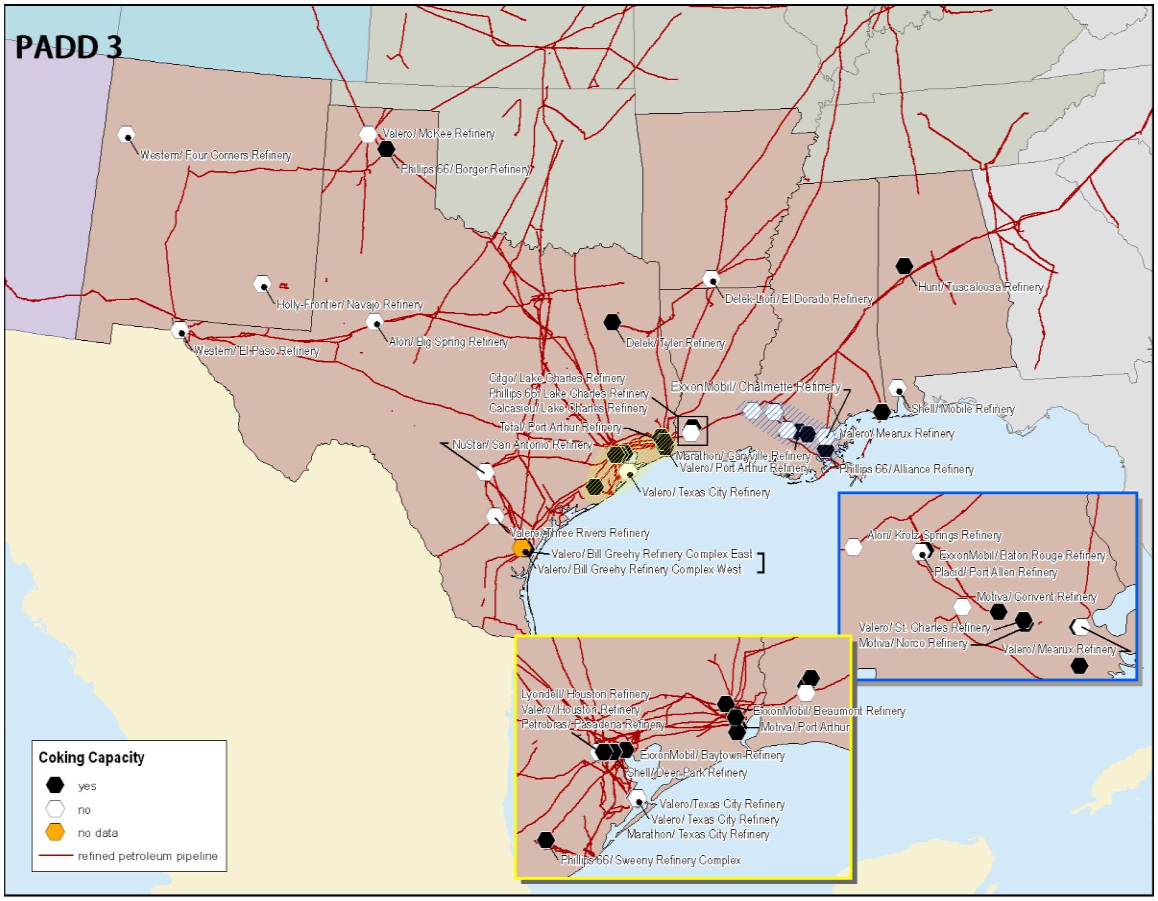


Source: CRS analysis of capacity data advertised on owner/operator websites.

Facility	City	State	Bbl/day
Phillips 66 Wood River Refinery	Roxana	IL	306,000
ExxonMobil Joliet Refinery	Drummond	IL	250,000
Marathon Robinson Refinery	Robinson	IL	206,000
Citgo Lemont Refinery	Lemont (Chicago)	IL	167,000
BP Whiting Refinery	Whiting	IN	413,000
CountryMark Refinery	Mount Vernon	IN	26,500
Holley Frontier El Dorado Refinery	El Dorado	KS	135,000
CVR Coffeyville Refinery	Coffeyville	KS	115,000
Cenex-NCRA McPherson Refinery	McPherson	KS	85,000
Marathon Catlettsburg Refinery	Catlettsburg	KY	233,000
Continental Somerset Refinery	Somerset	KY	5,500
Marathon Detroit Refinery	Detroit	MI	106,000
Flint Hills Pine Bend Refinery	Rosemont	MN	320,000
Northern Tier St. Paul Park Refinery	Saint Paul Park	MN	74,000
Tesoro Mandan Refinery	Mandan	ND	58,000
PBF Toledo Refinery	Toledo	OH	170,000
BP-Husky Refinery	Oregon/Toledo	OH	160,000
Husky Lima Refinery	Lima	OH	155,000
Marathon Canton Refinery	Canton	OH	78,000
Phillips 66 Ponca City Refinery	Ponca City	OK	187,000
Holly –Frontier Tulsa Refinery Complex (East Plant)	Tulsa		
Holly –Frontier Tulsa Refinery Complex (West Plant)	Tulsa	OK	125,000
Valero Ardmore Refinery	Ardmore	OK	90,000
CVR Wynnewood Refinery	Wynnewood	OK	70,000

Valero Memphis Refinery	Memphis	TN	195,000
Calumet Superior Refinery	Superior	WI	34,300
			3,764,300

Figure C-3. Operable Refineries in PADD 3

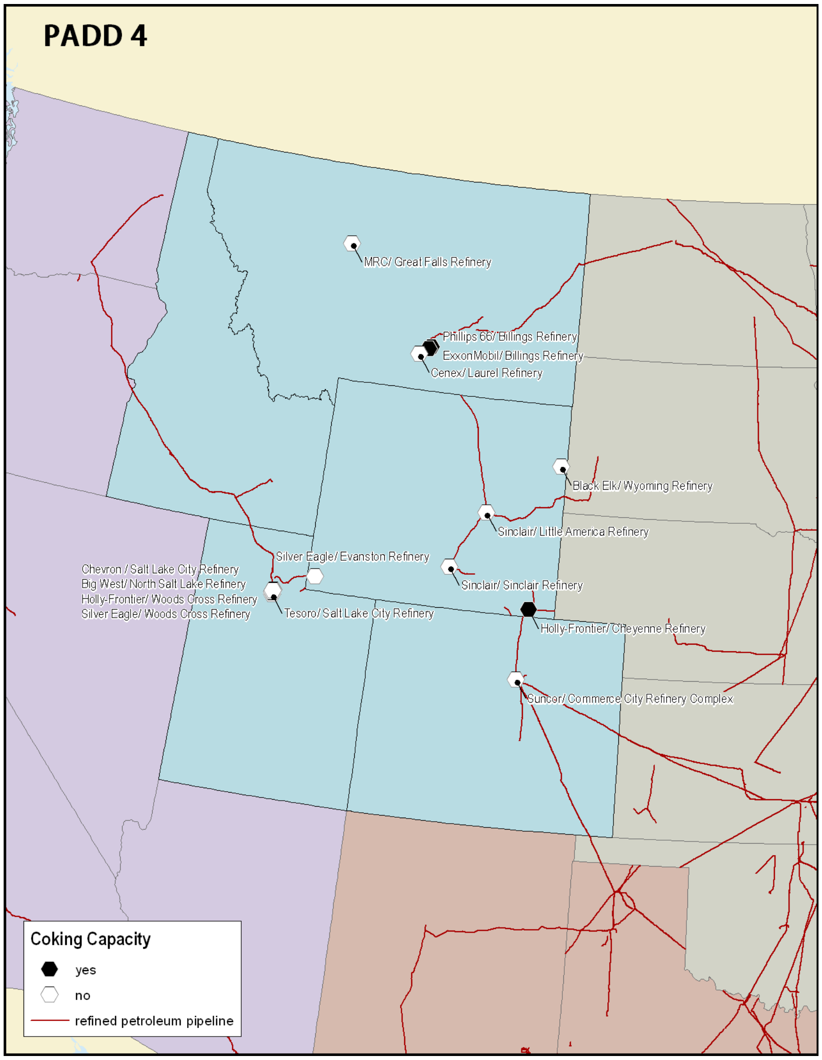


Source: CRS analysis of capacity data advertised on owner/operator websites.

Facility	City	State	Bbl/day
Shell Mobile Refinery	Saraland	AL	80,000
Hunt Tuscaloosa Refinery	Tuscaloosa	AL	72,000
Delek-Lion El Dorado Refinery	El Dorado	AR	80,000
ExxonMobil Baton Rouge Refinery	Baton Rouge	LA	503,500
Marathon Garyville Refinery	Garyville	LA	490,000
Citgo Lake Charles Refinery	Lake Charles	LA	425,000
Valero St. Charles Refinery	Norco	LA	270,000
Phillips 66 Alliance Refinery	Belle Chasse	LA	247,000
Phillips 66 Lake Charles Refinery	Westlake	LA	239,000
Motiva Convent Refinery	Convent	LA	235,000
Motiva Norco Refinery	St. Charles Parrish	LA	234,700
ExxonMobil Chalmette Refinery	Chalmette	LA	192,500
Valero Meraux Refinery	Meraux	LA	125,000
Alon Krotz Springs Refinery	Krotz Springs	LA	83,100
Placid Port Allen Refinery	Port Allen	LA	80,000
Calcasieu Lake Charles Refinery	Lake Charles	LA	32,000
Chevron Pascagoula Refinery	Pascagoula	MS	330,000

Facility	City	State	Bbl/day
Holly-Frontier Navajo Refinery	Artesia	NM	100,000
Western Four Corners Refinery	Gallup/Jamestown	NM	23,000
Motiva Port Arthur Refinery	Port Arthur	TX	600,000
ExxonMobil Baytown Refinery	Baytown	TX	573,000
Marathon Texas City Refinery	Texas City	TX	475,000
ExxonMobil Beaumont Refinery	Beaumont	TX	365,000
Shell Deer Park Refinery	Deer Park	TX	340,000
Valero Bill Greehy E. & W. Refinery Complex	Corpus Christi	TX	325,000
Valero Port Arthur Refinery	Port Arthur	TX	310,000
Lyondell Houston Refinery	Houston	TX	268,000
Phillips 66 Sweeny Refinery Complex	Sweeny	TX	247,000
Valero Texas City Refinery	Texas City	TX	245,000
Total Port Arthur Refinery	Port Arthur	TX	174,000
Valero McKee Refinery	Sunray	TX	170,000
Citgo Corpus Christi Refinery East & West Plant	Corpus Christi	TX	165,000
Valero Houston Refinery	Houston	TX	160,000
Flint Hills Corpus Christi East Refining Complex	Corpus Christi	TX	150,000
Flint Hills Corpus Christi West Refining Complex	Corpus Christi	TX	150,000
Phillips 66 Borger Refinery	Borger	TX	146,000
Western El Paso Refinery	El Paso	TX	128,000
Petrobras Pasadena Refining System Inc	Pasadena	TX	100,000
Valero Three Rivers Refinery	Three Rivers	TX	100,000
Marathon Texas City Refinery	Texas City	TX	80,000
Alon Big Spring Refinery	Big Spring	TX	70,000
Delek Tyler Refinery	Tyler	TX	60,000
NuStar San Antonio Refinery	San Antonio	TX	13,500
			9,256,300

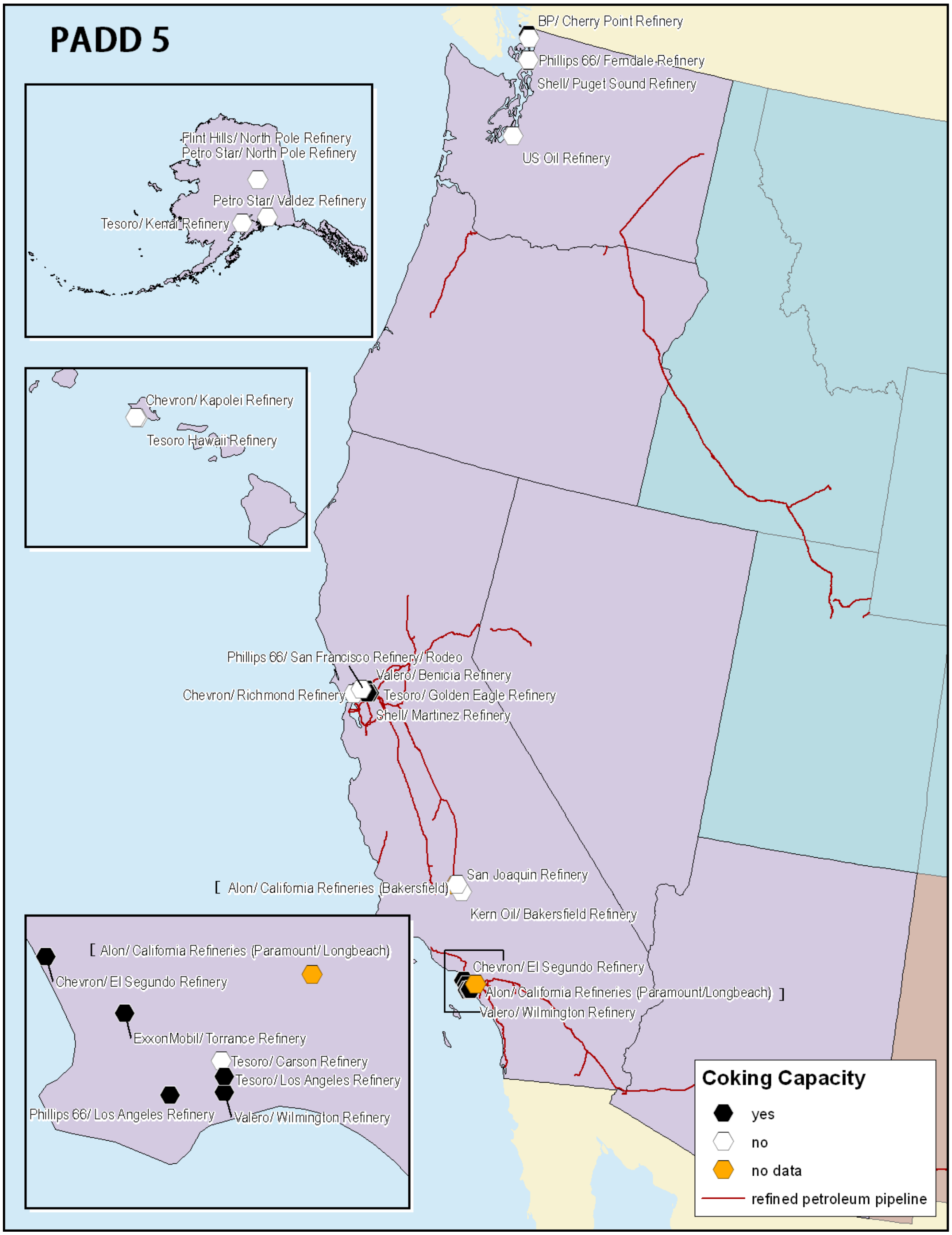
Figure C-4. Operable Refineries in PADD 4



Source: CRS analysis of capacity data advertised on owner/operator websites.

Facility	City	State	Bbl/day
Suncor Commerce City Refinery Complex	Commerce City	CO	93,000
ExxonMobil Billings Refinery	Billings	MT	60,000
Phillips 66 Billings Refinery	Billings	MT	58,000
Cenex Laurel Refinery	Laurel	MT	55,000
MRC Great Falls Refinery	Great Falls	MT	10,000
Tesoro Salt Lake City Refinery	Salt Lake City	UT	58,000
Chevron Salt Lake City Refinery	Salt Lake City	UT	45,000
Big West North Salt Lake Refinery	North Salt Lake	UT	35,000
Holly-Frontier Woods Cross Refinery	Woods Cross	UT	31,000
Silver Eagle Woods Cross Refinery	Woods Cross	UT	10,250
Sinclair Refinery	Sinclair	WY	66,000
Holley-Frontier Cheyenne Refinery	Cheyenne	WY	52,000
Sinclair Little America Refinery	Casper/Evansville	WY	24,500
Black Elk Wyoming Refinery	Newcastle	WY	12,500
Silver Eagle Evanston Refinery	Evanston	WY	3,000
			632,250

Figure C-5. Operable Refineries in PADD 5



Source: CRS analysis of capacity data advertised on owner/operator websites.

Notes: The Phillips 66 San Francisco Refinery comprises two facilities inked by a 200-mile pipeline — the Santa Maria facility located in Arroyo Grande, CA, and the Rodeo facility in the San Francisco Bay Area. The Santa Maria facility upgrades heavy crude oil for final processing in the San Francisco Bay facility. The Santa Maria facility is not on the map. The Phillips 66 Los Angeles Refinery Complex is composed of two facilities linked by a five-mile pipeline. The Carson facility serves as the front end of the refinery by processing crude oil, and Wilmington serves as the back end by upgrading the products.

Facility	City	St	Bbls/day
Flint Hills North Pole Refinery	North Pole	AK	220,000
Petro Star Valdez Refinery	Valdez	AK	60,000
Petro Star North Pole Refinery	North Pole	AK	22,000
Tesoro Kenai Refinery	Kenai	AK	72,000
Chevron El Segundo Refinery	El Segundo	CA	290,000
Tesoro Carson Refinery	Los Angeles	CA	266,000
Chevron Richmond Refinery	Richmond	CA	243,000
Valero Benicia Refinery	Benicia	CA	170,000
Tesoro Golden Eagle Refinery	Martinez	CA	166,000
Shell Martinez Refinery	Martinez	CA	165,000
ExxonMobil Torrance Refinery	Torrance	CA	150,000
Phillips 66 Los Angeles Refinery Complex/ Wilmington	Wilmington	CA	139,000
Phillips 66 Los Angeles Refinery Complex/ Carson	Carson	CA	
Valero Wilmington Refinery	Wilmington	CA	135,000
Phillips 66 San Francisco Refinery/Rodeo Facility	Rodeo	CA	120,000
Phillips 66 San Francisco Refinery/Santa Maria Facility	Arroyo Grande	CA	
Tesoro Los Angeles Refinery	Wilmington	CA	97,000
Alon California Refineries Paramount	Paramount	CA	
Alon California Refineries Longbeach	Longbeach	CA	94,000
Alon California Refineries Bakersfield	Bakersfield	CA	
Kern Oil Bakersfield Refinery	Bakersfield	CA	26,000
San Joaquin Refinery	Bakersfield	CA	24,300
Tesoro Hawaii Refinery	Kapolei	HI	94,500
Chevron Kapolei Refinery	Kapolei	HI	54,000
BP Cherry Point Refinery	Blaine	WA	230,000
Shell Puget Sound Refinery	Anacortes	WA	145,000
Tesoro Anacortes Refinery	Anacortes	WA	120,000
Phillips 66 Ferndale Refinery	Ferndale	WA	100,000
US Oil Refinery	Tacoma	WA	39,000
			3,241,800

Appendix D. Important Fuel Properties

Reid Vapor Pressure

Vapor pressure is an important physical property of both automotive and aviation gasoline, affecting starting, warm-up, and tendency to vapor lock with high operating temperatures or high altitudes. EPA regulates the vapor pressure of gasoline sold at retail stations during the summer ozone season (June 1 to September 15) to reduce evaporative emissions from gasoline that contribute to ground-level ozone and diminish the effects of ozone-related health problems. Shifting to gasoline with lower Reid vapor pressure (RVP) reduces emissions. The Reid Method refers to American Society for Testing and Materials (ASTM) standard test method D 323-08 for measuring the vapor pressure of petroleum products. RVP of conventional gasoline varies from 8.7 in the summer to 11.5 in the winter; reformulated gasoline (RFG) and state "boutique" fuel blends may have a summer RVP as low as 7.0.

Octane

Higher octane-number fuels better resist engine "knock"—the sound caused by fuel prematurely igniting during compression. In early gasoline research, the least knock resulted from using iso-octane, which arbitrarily received a rating of 100.[59] Isooctane refers to a branched "isomer" in the paraffin series having eight carbons (C_8H_{18}).[60] The straight-chain isomer in this series, n-octane, has a rating -19. Modern formulated gasoline ranges in octane from 87 to 93, achieved by blending various petroleum distillates, reforming gasoline-range hydrocarbons, and adding oxygenates such as ethanol to boost octane-number.

Cetane

The standard for rating diesel fuel's ease of auto-ignition during engine compression is based on "cetane"—a straight-chain hydrocarbon in the paraffin series with the common name of n-hexadecane. It consists of 16 carbon atoms with three hydrogen atoms bonded to the two end carbons and two hydrogens bonded to each of the middle carbons; written as $C_{16}H_{34}$. Pure cetane received the number 100 for rating purposes. Diesel fuel cetane-number ranges from 40 to 45 in the United States to as high as 55 in Europe (where high-speed diesel engines are prevalent in light-duty passenger vehicles). Diesel fuel formulation blends straight-run cut distillates with cracked stock (heavier fractions) to meet standardized specifications developed by the American Society for Testing and Materials (ASTM International) and EPA.

Sulfur

As now regulated by EPA (40 C.F.R. 80.520), diesel fuel must contain less than 15 parts-per-million (ppm) sulfur—referred to as ultra-low-sulfur diesel (ULSD). Conventionally refined aviation jet fuel may contain as high as 3,000 ppm sulfur. However, as it has been used in blending winter diesel fuel to lower the gel point, it has had a practical limit of 500 ppm (the previous EPA limit for diesel). It is uncertain whether EPA may promulgate future rules on jet fuel sulfur-content, thus limiting its use in blending winter ULSD. Despite its detrimental environmental effects, sulfur contributes to the "lubricity" of fuel. Under reduced sulfur, engines wear out sooner. Fuel can be blended with additives to make up for the loss of sulfur lubricity and

[59] John M. Hunt, Petroleum Geochemistry and Geology, W. H. Freeman and Co., 1979. p. 51.

[60] Or more correctly, 2,2,4-trimethylpentane.

engines can be manufactured from tougher materials, as has been the case in the EPA mandated transition from low-sulfur diesel (500 ppm) to ultra-low-sulfur diesel (15 ppm). Average annual sulfur content in all gasoline dropped from about 300 ppm in 1997 to a maximum of 30 ppm for most refiners in 2006.

Exhaust Emissions

Diesel engines characteristically emit lower amounts of carbon monoxide (CO) and carbon dioxide (CO_2) than gasoline engines, but they emit higher amounts of nitrogen oxides (NOx) and particulate matter (PM). NOx is the primary cause of ground-level ozone pollution (smog) and presents a greater problem, technically, to reduce in diesel engines than PM. The CO, NOx, and PM emissions for gasoline and diesel engines are regulated by the 1990 Clean Air Act amendments (42 U.S.C. 7401-7671q).

Appendix E. Glossary[61]

Motor Gasoline (Finished). A complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline (as defined in ASTM Specification D 4814 or Federal Specification VV-G-1690C) has a boiling range of 122º to 158º F at the 10% percent recovery point, and a 365º to 374º F boiling range at the 90% recovery point. "Motor Gasoline" includes conventional gasoline, all types of oxygenated gasoline (including gasohol), and reformulated gasoline, but excludes aviation gasoline. Volumetric data on blending components, such as oxygenates, are not counted in data on finished motor gasoline until the blending components are blended into the gasoline. Note: E85 is included only in volumetric data on finished motor gasoline production and other components of product supplied.

Conventional Gasoline. Finished motor gasoline not included in the oxygenated or reformulated gasoline categories. Note: This category excludes reformulated gasoline blendstock for oxygenate blending (RBOB) as well as other blendstock.

Reformulated Gasoline. Finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under Section 211(k) of the Clean Air Act. It includes gasoline produced to meet or exceed emissions performance and benzene content standards of federal-program reformulated gasoline even though the gasoline may not meet all of the composition requirements (e.g., oxygen content) of federal-program reformulated gasoline. Note: This category includes Oxygenated Fuels Program Reformulated Gasoline (OPRG). Reformulated gasoline excludes Reformulated Blendstock for Oxygenate Blending (RBOB) and Gasoline Treated as Blendstock (GTAB).

Blendstock for Oxygenate Blending (RBOB). Specially produced reformulated gasoline blendstock intended for blending with oxygenates downstream of the refinery where it was produced. Includes RBOB used to meet requirements of the federal reformulated gasoline program and other blendstock intended for blending with oxygenates to produce finished gasoline that meets or exceeds emissions performance requirements of Federal reformulated gasoline (e.g., California RBOB and Arizona RBOB). Excludes conventional gasoline blendstocks for oxygenate blending(CBOB).

RBOB for Blending with Alcohol. Motor gasoline blending components intended to be blended with an alcohol component (e.g., fuel ethanol) at a terminal or refinery to raise the oxygen content.

Fuel Ethanol (E10). Blends of up to 10% by volume anhydrous ethanol (200 proof) (commonly referred to as "gasohol").

[61] U.S. Energy Information Administration, *Glossary*, http://www.eia.gov/tools/glossary/index.cfm.

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